

June 6, 2006

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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FACT SHEET

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To: Commissioners
Cc: Martin, Kate
From: Will, Mike
Re: NWE QF Dockets: D2003.7.86, D2004.6.96, D2003.6.103

IN THE MATTER OF NORTHWESTERN ENERGY,) UTILITY DIVISION
Application for Approval of 2003 Avoided Cost)
Compliance Filing -- Schedules QFLT-1 and STPP-1) DOCKET NO. D2003.7.86

IN THE MATTER OF NORTHWESTERN ENERGY,) UTILITY DIVISION
Application for Approval of 2004 Avoided Cost)
Compliance Filing -- Schedules QFLT-1 and STPP-1) DOCKET NO. D2004.6.96

IN THE MATTER OF NORTHWESTERN ENERGY,) UTILITY DIVISION
Application for Approval of 2005 Avoided Cost)
Compliance Filing -- Schedules QFLT-1 and STPP-1) DOCKET NO. D2005.6.103

Introduction¹

This Fact Sheet regards NorthWestern Energy's (NWE's) last three filings with the Montana Public Service Commission (MTPSC) to revise its qualifying facility (QF) rates, terms and conditions.² NWE is required by federal and state laws to offer rates to cogeneration and small power producers that produce electric power. The three dockets respectively regard NWE's 2003, 2004 and 2005 QF rate proposals in D2003.7.86, D2004.6.96 and D2005.6.103. After providing some background, we will review the

¹ Prior to a hearing the utility division staff will route a Fact Sheet that summarizes the record, including information that may become evidence.

² On December 17, 2003, the MTPSC issued, in NWE's prior QF docket, Final Order No. 6434 (D2002.7.80).

procedural record (the procedural history is added for completeness but you may want to skip over it in your first reading of this Fact Sheet). We next summarize the MTPSC's orders on additional issues. This is followed by a summary of the NWE and intervenor testimony, of which there are eleven summaries. Consistent with prior Fact Sheets when we summarize a party's testimony we reference relevant data responses that may become part of the evidentiary record (e.g., DR PSC -001). As necessary, we will request a pre-hearing work session in order to aid in the preparation for the hearing.

According to the last March 31, 2006 Notice of Staff Action (NSA), the hearing will commence July 12, 2006.

Background

In 1978, Congress enacted five energy-related bills, one of which was the Public Utility Regulatory Policies Act (PURPA). The overarching mandate of Section 210 of PURPA served was to encourage cogeneration and small power production. The mandate was to be achieved by paying QFs a rate for energy that is not higher than the incremental cost to the electric utility of alternative electric power. Section 210 sets forth the obligations and standards by which the FERC must establish rules to implement PURPA. The FERC's March 20, 1980 rules (18 CFR 292) set forth expectations of the costs that shall serve as the basis for energy and capacity payments by electric utilities to QFs.

The Montana Legislature enacted in 1981 a PURPA-related statute (§69-3-601 et. seq.).³ This "Small Power Production Facilities" statute required a public utility that supplies electricity and that is regulated by the MTPSC to purchase power from QFs. The statute also features a "120" day provision -- for the occasions when a QF and a utility are unable to agree to a contract or a price. The MTPSC may set QF rates based upon avoided costs, the QF's cost of production or by means of another method so long as the result promotes the development of such facilities.

The MTPSC established rules that adopt by reference the FERC's rules and that set forth general requirements and criteria, including the mutual obligations that QFs and electric utilities have to one another (A.R.M 38.5.1901 et seq.). These Cogeneration and

Small Power Production rules require, among other provisions, “standard” rates for QFs that do not negotiate a rate. These 1981 rules were amended in 1992 to limit the availability of long-term contracts. For QFs that exceed 3 MWs in size, selection is via an all-source competitive solicitation. Between solicitations, and for QFs larger than 3 MWs, rates must be based on either the “standard” offer or established through a negotiated short-term rate. The MTPSC may set standard long-term rates for QFs smaller than 3 MWs. As amended, such rules also require that QF rates be compatible with the MTPSC’s integrated least-cost planning and acquisition guidelines.

During the 1980s, the MTPSC initiated and concluded three generic QF dockets, each of which established policies and new QF rates. These three dockets (D81.2.15, D83.1.2 and D84.10.64) continue to impact avoided cost ratemaking. The former two dockets rates and policies are at issue in the present consolidated (D2003.7.86 et al) cases. The MTPSC also established QF rates in limited purpose dockets such as for Billings Generation Inc (BGI, D90.8.51).

Section 1253 of the Energy Policy Act of 2005 (‘05 Act) continues the obligation to enter into new contracts or obligations to purchase electric energy from QFs but only so long as the FERC finds that QFs do not have nondiscriminatory access to either (1) an independently administered, auction-based day-ahead and real-time wholesale market; (2) transmission and interconnection services administered pursuant to an open access -- nondiscriminatory -- transmission tariff and competitive wholesale markets with a meaningful opportunity to sell energy and capacity to buyers other than the host utility; or (3) wholesale markets for the sale of capacity and energy that are, at a minimum, of comparable competitive quality as such markets.

We next summarize the procedural history for these three consolidated dockets.

Procedure

The procedural history in these three consolidated dockets is lengthy, if not epic. After this review of the procedural events we will summarize the filed testimony.

³ The 2003 Montana legislature repealed these statutes “on occurrence of contingency” and upon the effective date of PURPA’s repeal (see HB 417, §69-3-601(4)).

On June 30, 2003, NWE submitted its Annual Avoided Cost Compliance filing in docket D2003.7.86. NWE's filing contained a motion for an interim increase, a motion for a protective order and a request for interim approval of the STPP (Short Term Power Purchase) and the QFLT (Qualifying Facility/Long-Term) rates. NWE asserts that in order to establish rate variables that are consistent with the stipulation reached in D2002.7.80 an "incremental calculation" was performed.⁴

On July 17, 2003, CELP (Colstrip Energy Limited Partnership) petitioned to intervene and filed Nondisclosure Agreements signed by each of Michael J. Uda and Kevin Woodruff. The Montana Consumer Counsel (MCC) filed on September 26, 2003 to intervene. On October 14, 2003 Roger Kirk filed to intervene. Navitas Inc (NEI in the following) manages Whitehall Wind LLC and filed on October 31, 2003 for late intervention.

The MTPSC released on August 18, 2003 its Interim Order granting NWE's request to approve the adjusted rate elements on the QFLT-1 and STPP-1 schedules.

The settlement rates, the proposed rates and the interim approved rates are as follows:

	<u>D2002.7.80</u>	<u>D2003.7.86</u>	<u>Interim D2003.7.86</u>
	<u>Settlement Rates</u>	<u>Proposed Rates</u> ⁵	<u>Approved Rates</u>
Escalating			
Energy	4.4593¢/kwh	4.5106¢/kwh	4.5106¢/kwh
Capacity	\$69.9920/kw/yr	\$70.1270/kw/yr	\$70.1270/kw/yr
Partially Escalating			
Energy	1.5100¢/kwh	1.5557¢/kwh	1.5557¢/kwh
Capacity	\$1.718/kw/yr	\$1.726/kw/yr	\$1.726/kw/yr
System Lambda	1.0639¢/kwh	1.1283¢/kwh	1.1283¢/kwh

The MTPSC issued on September 18, 2003 its Notice of Additional Issues

⁴ A February 6, 2003 Fact Sheet summarized the record in the prior NWE avoided cost docket, D2002.7.80.

⁵ The escalating rates are on the QFLT (Qualifying Facility Long Term) tariff and system lambda is on the STPP (Short Term Power Purchase) tariff. In its June 30, 2003 filing NWE asserts that the STPP was modified to coordinate with the QF-1 schedule that applies to QFs less than 3 MWs in size and that requires larger QFs to participate in RFPs to serve default supply. NWE intends to refile the QF-1 rate when it submits its prehearing memorandum. (DR PSC -075(d), but also see DR PSC -86(c))

(reviewed below).

In an October 30, 2003 Notice of Commission Action (NCA) the MTPSC denied a NWE request to suspend the docket.

The MTPSC issued on December 17, 2003 Procedural Order (No.6501b) that set forth dates for both the filing of testimony and an initial hearing date. NWE filed on January 2, 2004 a Motion for Reconsideration of the Procedural Order, setting a May 26, 2004 hearing date and seeking to extend each milestone in the order by 90 days. On January 12, 2004 NEI responded to NWE's Motion for Reconsideration asserting that its due process rights had been violated and asking that the MTPSC deny NWE's Motion. The MTPSC on February 6, 2004 denied reconsideration of its Procedural Order No. 6501b.

In conjunction with prefiled testimony on additional issues, NWE filed on January 20, 2004 (letter dated January 15, 2004) an objection to the additional issue relating to contracts (also reviewed below); NWE simultaneously filed the Supplemental Testimony of Mark A. Stauffer addressing the MTPSC's additional issues. On January 21, 2004, intervenor CELP joined in NWE's objection. On January 30, 2004, the MTPSC overruled without prejudice the objections.

On February 20, 2004, Two Dot Wind, LLC (TDW) filed a petition for late intervention seeking relief in the form of a MTPSC finding that renewable energy credits (RECs) be separately and expressly conveyed by developers of QFs to the "utilities for value." For QF contracts in place TDW's petition asks that RECs not be transferred unless the contract provides for such transfer. NWE filed on February 27, 2004 its objection to TDW's Petition for Late Intervention. TDW filed on February 27, 2004 its Reply in support of its petition for late intervention. The MTPSC identified on February 23, 2004 Renewable Energy Credits (RECs) as a further additional issue and then allowed an opportunity for interested persons to intervene for the purpose of addressing REC issues.

The MTPSC in a March 17, 2004 notice of action responded to TDW's petition (action taken at the February 23, 2004 agenda meeting) granting it intervener status and permitting an additional issue procedure to address the REC issue raised by TDW's

petition. Boulder Hydro Limited Partnership filed on April 8, 2004 to intervene in relation to the REC issue.

NEI filed on April 15, 2004 an objection to MTPSC discovery DR PSC -053(e).

Whitehall Wind, LLC (WHW) filed a notice of substitution of parties with the result that WHW was substituted for NEI.

NWE filed on May 4, 2004 its objection to NEI data request DR NEI-027. NEI filed on May 7, 2004 its response to NWE's objection.

The MTPSC received on May 11, 2004 NWE's application for a Protective Order. NEI then filed on May 12, 2004 its motion for a protective order.

WHW filed on May 17, 2004 its leave to file a surreply and a brief in response to NWE's objection to NEI's data request DR NEI -027(b).

On May 18, 2004, NWE responded to NEI's position on DR NEI -027.

On May 19, 2004, WHW requested to continue the hearing.

An initial staff Fact Sheet in D2003.7.86 was routed on May 20, 2004. That Fact Sheet was expanded to incorporate the three consolidated dockets and additional issues, resulting in the present comprehensive Fact Sheet.

NWE submitted on June 28, 2004 (dated June 25th) its 2004 Annual Avoided Cost Compliance filing that was docketed D2004.6.96. NWE's 2004 filing updates rates and supporting work papers but does not raise any new issues. Due to a higher escalation factor NWE proposed to increase its QFLT-1 rates. The proposed STPP-1 rate declines due to lower coal costs. NWE asked that the MTPSC simultaneously process the 2004 and 2003 filings. The MTPSC also issued on October 13, 2004 a Notice of Commission Action consolidating D2003.7.86 and D2004.6.96. The prior interim rates, the proposed interim rates and the approved interim rates are as follows:

	<u>Interim D2003.7.86</u>	<u>D2004.6.96</u>	<u>Interim D2004.6.96</u>
Escalating	<u>Approved Rates</u>	<u>Proposed Rates</u>	<u>Approved Rates</u>
Energy	4.5106¢/kwh	4.6578¢/kwh	4.6578¢/kwh
Capacity	\$70.1270/kw/yr	\$73.026/kw/yr	\$73.026/kw/yr
Partially Escalating			
Energy	1.5557¢/kwh	1.5625¢/kwh	1.5625¢/kwh
Capacity	\$1.726/kw/yr	\$1.7580/kw/yr	\$1.7580/kw/yr
System Lambda	1.1283¢/kwh	1.1146¢/kwh	1.1146¢/kwh

The above proposed rates received interim approval on September 7, 2004 and were effective for service on July 1, 2004.

NWE filed on December 7, 2004 a limited objection to WHW's data request DR WHW -011. The MTPSC issued on February 17, 2005 a notice on discovery that also mentions the December 7, 2004 suspension of the procedural schedule and that, among other things, ordered NWE to provide to WHW non-proprietary information that was requested in DR WHW -011. NWE filed on February 23, 2005 its response to DR WHW -011. WHW filed on March 3, 2005 its "Motion to Compel Production by NWE of Actual Cost Data and Memorandum in Support." This WHW motion found inadequate the non-proprietary material supplied by NWE. NWE filed on March 15, 2005 its reply to WHW's motion. WHW next filed on March 17, 2005 a reply in support of its own motion.

On June 13, 2005 NWE filed a Stipulation between NWE and CELP on Additional Issues 1 and 2 (these issues are discussed later).

NWE filed on June 24, 2005 its 2005 Annual Avoided Cost Compliance filing in D2005.6.103. In a July 20, 2005 NCA the MTPSC consolidated D2005.6.103 with the former two pending QF dockets and it interim approved NWE's proposed rates. On July 20, 2005 the MTPSC issued Order 6675 in Docket D2005.6.103 approving, on an interim basis, NWE's proposed updates to the QFLT-1 and STPP-1 rate schedules.

The following table summarizes the interim approved rates, the proposed interim rates and the interim approved rates in D2005.6.103:

	<u>Interim D2004.6.96</u>	<u>D2005.6.103</u>	<u>Interim D2005.6.103</u>
	<u>Approved Rates</u>	<u>Proposed Rates</u>	<u>Approved Rates</u>
Escalating			
Energy	4.6578¢/kwh	4.2415¢/kwh	4.2415¢/kwh
Capacity	\$73.026/kw/yr	\$65.765/kw/yr	\$65.765/kw/yr
Partially Escalating			
Energy	1.5625¢/kwh	1.5831¢/kwh	1.5831¢/kwh
Capacity	\$1.7580/kw/yr	\$1.7940/kw/yr	\$1.7940/kw/yr
System Lambda	1.1146¢/kwh	1.1145¢/kwh	1.1145¢/kwh

On July 20, 2005 the MTPSC issued Order No. 6675 in Docket D2005.6.103 approving, on an interim basis, NWE's proposed updates to the QFLT-1 and STPP-1 rate

schedules. On the same date, the MTPSC issued a NCA that consolidated Docket D2005.6.103 with Dockets D2004.6.96 and D2003.7.86.

On August 31, 2005 NWE moved to suspend consideration of all issues related to prospective QF power purchase contracts.⁶ On September 9, 2005, WHW objected to NWE's motion. On September 14, 2005 WHW and Boulder Hydro filed motions to reset the procedural schedule and to require NWE to file a motion for protective order. On September 15, 2005 NWE filed a response to WHW's objection to its August 31 motion to suspend. On September 19, WHW replied to NWE's September 15 response. On September 29, 2005 NWE filed amendments to its 2004 and 2005 Annual Avoided Cost Compliance Filings which affected rates for the July 2004 – June 2005 and July 2005 – June 2006 contract years. On September 30, CELP filed motions opposing NWE's amendments to interim QF rates and requesting a hearing. In an October 3, 2005 NCA, the MTPSC denied NWE's motion to suspend, granted the intervenors' motions to require NWE to file a protective order and denied the intervenors' motions to reset the procedural schedule. NWE identified in response to DR PSC -146(d) its September 28, 2005 motion to amend as the only outstanding rate amendment request for which it continues to seek MTPSC approval.⁷

On November 16, 2005, CELP and NWE jointly moved to suspend the proceedings. On November 18, 2005, the MTPSC issued a Protective Order. On November 28, 2005 NWE filed a brief in support of its motion for a protective order. On December 5, 2005, WHW submitted comments on NWE's motion to reconsider special terms and conditions for a protective order.

⁶ In an October 3, 2005 NCA the PSC denied NWE's motion to suspend, with qualifications. The PSC chose not to suspend consideration of any issues in the above consolidated dockets at this time. The PSC did not agree with NWE's assessment that the Energy Policy Act of 2005 and the Federal Energy Regulatory Commission's responsibilities pursuant to that Act warrant PSC suspension of any issue in these NWE qualifying facility proceedings. The issues in these consolidated dockets relate to existing as well as prospective qualifying facilities. As these dockets progress, NWE may identify specific issues and make specific arguments as to why the PSC should be cautious in action on those issues.

⁷ NWE computes the amount that CELP would receive and that would be in the QFLT tariff assuming approval of NWE's amendments to interim rates. DR PSC -146(e)

On December 6, 2005 the MTPSC issued a NCA on joint motion to suspend that CELP and NWE filed. The MTPSC denial was without prejudice. On December 14, 2005, the MTPSC issued its NCA on motions for reconsideration of denial of protective order and special terms and condition.

On February 2, 2006, the Montana Department of Natural Resources and Conservation (DNRC) petitioned to intervene. On February 23, 2006, CELP motioned for an interim rate adjustment based on the incremental cost of capital. On March 7, 2006, NWE responded to CELP's motion for interim rate adjustment. On March 10, 2006, CELP motioned for leave to file surrebuttal testimony and filed the surrebuttal of Mr. Lauckhart.

On March 14, 2006 the MTPSC issued: 1) a NSA amending the procedural schedule and setting an April 19, 2006 hearing date; 2) a NCA deferring consideration of CELP's motion for an interim rate adjustment; and 3) a NCA allowing DNRC intervention. March 21, 2006, NWE filed its objection to CELP's motion to file surrebuttal testimony. A March 31, 2006 NSA rescheduled the hearing to begin July 12, 2006. On the same date, the MTPSC issued a NCA granting CELP's petition to file surrebuttal testimony, and allowing a NWE response. As the above comprises most procedural events we now provide background on the origin of QF policies and rates.

We next summarize the additional issues that the MTPSC raised in the present NWE consolidated QF dockets.

Commission's Additional Issues

On September 18, 2003 the MTPSC raised the following additional issues on which additional testimony was allowed:

Issue 1. Contract Issues: Whether and how the CELP (Colstrip Energy Limited Partnership) contract was amended since initially consummated with NWE (f/k/a MPC). The inclusion of security and liquidated damages provisions in CELP's contract with NWE.

Issue 2. STPP Issues: The analytical basis for energy and capacity rates. The merit of opportunity cost values, sales and purchases, for energy and capacity rates.

Issue 3. Long-Term Tariff for Small QFs: Whether there is merit in a long-term standard avoided cost rate option for relatively small QFs. One threshold for small is the 3 MW criterion in existing rules. (A.R.M. 38.5.1902(5)) Another matter regards the cost/market basis for energy and capacity rates for such a tariff. Still another matter regards the allowed length of long-term contracts (e.g., 4 to 35 years). How any rate options should be levelized is another related issue (e.g., fully, partially levelized). Finally, the appropriate cost basis for such a rate is of paramount interest. Options for the cost basis include but are not limited to full requirements contracts (e.g., that NWE has with PPL), short- and long-term opportunity values (sales and purchase values) in the markets accessible to NWE for firm and non-firm power; another option might include direct reference to recognized market prices (e.g., COB, Mid-Columbia, or Mid-C) with appropriate adjustments for transmission.

Issue 4. Technology Based Rates: Whether merit exists in separate non-discriminatory and standard rates for the various qualifying small power production and cogeneration technologies.⁸ Candidate technologies include hydro, wind, fossil fuels, and renewable energy fuel sources e.g., hog fuel. The analytical basis for such rates (e.g., the long-term rate discussed in Issue 3 above).

Issue 5. Limited QF Power Procurement: Whether it is legal and whether it is advisable to place limits on the amount of QF power NWE would be obliged to acquire under a newly tariffed long-term or under a short-term contract (e.g., the STPP), for QFs less than 3MWs in size.

Commission's Supplemental Additional Issue: Renewable Energy Credits

In a March 17, 2004 NCA the MTPSC addressed the REC issue raised in the petition to intervene filed by TDW (now represented by WHW). In the context of these consolidated QF dockets, the issue involves how RECs should be treated prospectively in contracts between NWE and QFs, specifically which party may claim ownership of the RECs and whether any independent value associated with the RECs should be incorporated into rates paid to QFs. NWE opposed TDW's petition to intervene,

⁸ This issue was raised during an August 21, 2003 hearing in the matter of D2002.6.63.

asserting that RECs were not an identified issue in the proceeding. However, the MTPSC, noting that it had already expanded the scope of the proceeding with five additional issues on September 18, 2003, determined that REC issues should also be explored. The MTPSC directed NWE to file supplemental testimony addressing REC issues, allowed a further opportunity to intervene on REC issues, and provided opportunities for discovery and subsequent intervenor testimony.

Testimony

The balance of this Fact Sheet reviews, in turn, the following testimony: (1) NWE Additional Issues Testimony of Mark Stauffer; (2) CELP (Colstrip Energy Limited Partnership) Testimony of Owen Orndorff, (3) Navitas Energy Inc. (NEI or Navitas) testimony of Christopher Moore, (4) Two Dot Wind LLC (TDW) testimony of Van Jamison, (5) NWE Supplemental Additional Issue Testimony of Mark Stauffer, (6) NWE Rebuttal Testimony of Mark Stauffer (7) CELP Direct Testimony of Richard Lauckhart, (8) White Hall Wind Direct Testimony of Robert Frantz, (9) NWE Rebuttal Testimony of Mark Stauffer, (10) CELP Proposed Surrebuttal testimony of Richard Lauckhart and (11) NWE Surrebuttal testimony of Mark Stauffer.

NWE Additional Issues Testimony: Mark Stauffer

Mark Stauffer, NWE's economist, filed testimony on January 20, 2004 addressing the PSC's five additional issues. As for the first issue, he asserts that NWE has no contract related issues that are appropriate in this docket as all rate changes in this contract were approved by the PSC.⁹ He also notes NWE's objection to issue number one that was filed concurrently with this testimony. He concludes that NWE's 2003 compliance filing accurately reflects the appropriate method used to compute the QFLT-1

⁹ NWE explained that due to the difficulty in obtaining water rights and project financing CELP initiated a contract amendment, an amendment that incorporates "security" into the price terms. (DR PSC -014)

rate for all contracts, including ones (e.g., CELP's) that make reference to the QFLT-1 rates.¹⁰

As for the second issue, Stauffer recommends closing the STPP rate to new offerings.¹¹ Given the present use of the rate, he adds that its computation should be

¹⁰ NWE has contracts with CELP, Jenni Hydro and Pine Creek that reference the QFLT-1 rates and that are used to change the adjusting portion of the payment under these contracts. (DR PSC-003(a)) In regard to when CELP is unavailable to provide power, NWE explained how "unplanned outages" impact capacity payments by way of an adjustment in the next year adding that excess energy is paid a "negotiated rate." (DR PSC -015(a),(d))

¹¹ NWE explained its understanding of the basis of the STPP. (DR PSC -005) NWE also provided a table with historical STPP rates. (DR PSC -004(c)) If not closed and if the STPP is based upon the MTPSC's D81.2.15 and D83.1.2 orders to allow for separate energy and capacity rates, NWE estimates an energy rate of \$11.283/Mwh and a capacity rate of \$4.709/Mwh. These values appear to exclude opportunity costs as NWE purchased energy from PPL at \$31.15 (for 300 MWs of firm power) and at \$34.93 (for 150 MWs of heavy load contingent power); NWE estimates most opportunity sales to be into the Mid-C market. (DR PSC -006) Because it does not have dispatchable units NWE cannot compute system lambda.

NWE asserted that the PNW (Pacific Northwest) power market is dysfunctional with considerable price instability and that the use of regional power markets as a source of opportunity costs for a five year proxy rate would be extremely speculative. (PSC -007(a)) MPC previously based its "out of market" costs for QF contracts upon three sources of cost estimates. (DR PSC-017) NWE asserted that an estimate of the regional market value for firm power was filed in its D2003.8.115 (12/15/03) tracker and that it does not have non-firm power prices as requested in the data request. (DR PSC -007(c)) NWE asserted that if it had inadequate supplies of energy and capacity in the 2004 to 2008 time period, it would have no choice but to turn to the "market" for incremental purchases and at costs contained in its tracker citation. NWE added that the large resources developed in Montana compete in the dysfunctional PNW market where there is wholesale competition. Besides the Mid-C market there are numerous RFPs offered by numerous utilities in the region that are open to any producers and therefore "large" QFs have numerous opportunities to sell their resources in the competitive PNW market. (DR NEI -013) NWE proposed to discontinue the STPP rate because system lambda, on which the rate is based, reflects avoidable incremental dispatch costs and NWE disfavors changing the basis of the STPP rate. (DR PSC -018) NEI stated that the STPP is not appropriate for any QF as it is, apparently, "undefined." In addition, the STPP should not be used with QFs larger than 3 MW in size. (DR NWE-01, DR PSC -028(b), and PSC -029) NEI expressed concern that the STPP is not a long term rate. (DR PSC -030) NEI held that NWE's system lambda was on the order of \$.001639/kwh. (DR PSC -031)

found consistent with that usage and should not be altered. He asserts that the rate is limited to payments for power in excess of firm obligations of specific QFs and, as such, it is for non-firm power.¹² Therefore, a capacity payment is not warranted as NWE cannot rely on this power being available to serve loads.¹³ NWE can only “resell the power after incurring transmission and administrative expenses.” (p. 3) Until the rate is not used, NWE would update the rate in the manner proposed in its 2003 Compliance Filing.¹⁴

As regards the third additional issue, Stauffer testifies that the availability of the QF-1 rate should continue, updated whenever NWE completes a RFP (request for proposals).¹⁵ Given the dynamic nature of the NWE supply portfolio and the PURPA

¹² NWE advocates using the STPP rate for existing contracts involving non-firm power. (DR PSC -065(a)) NWE also explained that the Pony Generating Station uses the STPP for volumes in excess of 300/kw/hour and that both the new South Dry Creek and the new Strawberry Creek contracts have defaulted to STPP rates “under expiration of response time in a contract termination.” (DR PSC -003(b)) NWE recited the MTPSC’s intent for the STPP to include energy and capacity and added that the STPP does not apply to CELP’s excess energy production which is subject to a negotiated energy rate. (DR PSC -015) NWE admitted that there is no supplier of energy at a price of \$.011283 (the contract year STPP rate) except for QFs from whom it is required to buy sporadic non-firm energy on a long-term contract basis. NWE added that it has no intent to purchase additional amounts which have no value to firm load customers. (DR PSC -016)

¹³ NWE provided \$94.71/kwh/yr as the annual capacity cost for a combustion turbine (sic, \$/kw in the data request but \$/kwh in NWE’s response). (DR PSC -003(e))

¹⁴ NWE’s June 30, 2003 filing used, as did its D2002.7.80 compliance filing, a full year of invoices for coal costs. NWE inflated the cost to current year dollars which it held is a fair and sustainable method to compute coal costs consistent with Order No. 5017 (D83.1.2). NWE added that the proposed rates have increased relative to the settlement rates, due primarily to the increased cost of coal and to escalation factor increases. The filing also proposed to modify the applicability of the STPP-1 to coordinate with the QF-1 rate schedule. Since the QF-1 applies to QFs with an installed capacity of 3 MWs or less the STPP must be modified “to address QF projects” greater than 3 MWs that deliver power between solicitations.

¹⁵ NWE explained that the QF-1 rate for the 2003/2004 contract year was based on “a” contract (with Duke Energy) in the portfolio as it “...was judged the best indicator of the market value of QFs since it was a unit contingent power from Colstrip No. 3 and No. 4, baseload fossil fueled units like BGI and CELP, the largest QFs.” (DR PSC -018) NWE clarified that with its proposal the contract rate and length would be based on specific

requirement for accurate avoided costs, the rate should be updated at least annually. The present method of tying the “single” rate to the weighted average cost of non-QF acquired resources in NWE’s portfolio should continue and contract terms should not exceed 5 years.¹⁶ In addition, he favors placing limits on the quantity and terms of

“marginal RFP contracts.” Therefore, once a QF signs a contract, the rate and the contract length is fixed; if NWE is “forced” to sign contracts of a duration longer than the avoidable length associated with the cost, then the contract rate should be revised each time there is an addition to the “RFP.” (DR PSC -080(a))

¹⁶ NWE explained that the theoretic basis for the QF-1 rate is the cost that NWE would otherwise pay for power if it did not acquire power from the QF receiving the QF-1 rate. It also is for firm power based upon the weighted average rate paid to default suppliers for firm power, including payments for energy and capacity, and is therefore based on “market based marginal costs.” (DR PSC-008) NWE explained later, in response to PSC -013(a), that its proposed rate shown in response to PSC -008(e) had been revised, pursuant to MTPSC Order 4865, FOF 31 that states “...a separate annualized capacity payment based on the costs of a combustion turbine paid in proportion to a 85% availability factor is to be developed.” NWE clarified that the basis for the present QF-1 rate is not the weighted average of non-QF resources in the Company’s portfolio. Rather, it is NWE’s proposal to replace the present rate with the weighted average cost of non-QF resources. (DR PSC -012(b)) In a follow up response (DR PSC -141(a)), NWE explained how the QF-1 rate includes Basin Creek costs. Assuming that the use of the weighted average cost of the utility’s most recently completed RFP process is representative of the most economical power available NWE believes it provides a good approximation of what would otherwise be acquired and is therefore, apparently, avoided cost based. (DR PSC -013(b)) While other sources for the marginal cost of capacity may exist, NWE does not believe that use of the regional spot market is appropriate. (DR PSC -013(c)) NWE added that because QF contract rates are not part of the calculation there is no circularity in a weighted average rate; rates could be based on take-or-pay contracts. (DR PSC -080(c), (e)) NWE responded, in part, to a request to provide the resources and rates that would be in the weighted average rate (DR PSC -066(a)); after responding NWE held that its response should have been protected. (DR PSC -82) When asked why an accurate reflection of rates, given no distinction between energy and capacity, is revenues divided by Mwh sales, NWE responded that it intends to “allocate” the rate to demand and diurnal energy components. To establish the total cost basis to serve DSP load, NWE proposed combining the costs of all marginal contracts which would then be divided by the total power provided by those contracts. (DR PSC -081(a)) As the portfolio is the appropriate basis for avoided costs, NWE did not recommend contract terms in excess of five years. NWE did add that the term of contract is as significant an issue as is the price and quantity. (DR NEI -022) NWE added that long term contracts offer less flexibility to respond to changes in market prices and therefore pose more risk for stranded costs. (DR NEI -011) NWE explained why it opposes the inclusion of opportunity sales in the QF. (DR PSC -066(b))

smaller QF projects with larger QFs being required to participate in RFPs.¹⁷ In this regard, he advises the PSC to be cautious so as not to “repeat QF events of the past” that might result in new stranded costs. Due to the likelihood of new federal legislation that amends PURPA to have a more “market-based prospective,” (sic) and if need exists in its load/resource balance, NWE proposes to make the QF-1 available to QFs larger than 3 MWs on a temporary, “between RFP,” basis, but for no longer than 5 years.¹⁸ (p. 4) Thus, if the STPP is eliminated, the QF-1 would be available to all large QFs until contracts are awarded at the conclusion of an RFP.¹⁹ If a large QF is not awarded a contract, it must then wait until the next RFP. Stauffer refers to the fourth issue (below) for a further discussion of his position on long-term contracts.

As for the fourth issue, involving non-discriminatory technology based rates, Stauffer holds that if the PSC adopts NWE’s proposal and makes the QF-1 rate available on a 5-year or less basis to large QFs, then it is necessary to “break” the rate into capacity and energy components.²⁰ The capacity price should reflect a combustion turbine’s

¹⁷ As for how “large,” size would be determined as a function of a complete project at a particular site. If machines were located at the same site, the size would be the sum of the installed capacity of all machines. (DR PSC -082(a))

¹⁸ NWE explained that “need” is defined as a positive difference between the expected load to be served less the contracted resources available to serve that load. (DR PSC -012(e))

¹⁹ NWE explained how it computes the QF rate in its response to DR PSC -086(c) and DR PSC -141. For other resources, for example Tiber, NWE agreed to a capacity-only payment because the facility only produces on a run-of-river basis. Thompson River Cogen, on the other hand, is only paid on an energy basis. (DR PSC -087(d)) NWE filed on July 2, 2004 its late-filed response to DR PSC -087.

²⁰ NWE proposed dividing the rate into energy and capacity to reflect the two distinct market products and to incent producers to provide energy when it is most valuable, in addition, consistent with MTPSC orders in D83.1.2 and D84.10.64. (DR NEI-016) NWE added that it is fair to adjust capacity to account for intermittent resources such as wind. (DR NEI -019) NEI, however, does not believe that QF rates should depend on whether the type of generator provides for different payments based upon whether the generator is baseload, intermediate, intermittent or a peaking resource. (DR NWE -09) TDW did not agree that bids which NWE received in a recent request for wind projects are indicative of NWE’s avoided costs for QFs, intermittent or otherwise. (DR PSC -060(b))

(CT's) annual capital cost and the energy rate the remainder (the total rate less the CT cost).²¹ Stauffer also proposed a technology adjustment to the capacity rate. The result is that the annual capacity rate would be adjusted by the QF's capacity factor relative to the portfolio's capacity factor.²²

As for the fifth and last issue, on limiting the acquired QF power, Stauffer referred to his response to the third issue and his attached Exhibits MAS-2 and MAS-3.

Colstrip Energy Limited Partnership (CELP) Testimony: Owen Orndorff

On March 4, 2004 CELP filed the testimony of Owen Orndorff. Orndorff addressed the MTPSC's first additional issue involving CELP's contract. He first explains why CELP disagreed with the MTPSC for having raised the issue. He understands the issue to be one of why the security and liquidated damage provisions, in the original (unamended) CELP/MPC Power Purchase Agreement (agreement), were eliminated. Given the MTPSC's prior conclusions on its jurisdiction over such a matter, he holds that the MTPSC has incorrectly raised this issue. The MTPSC's present inquiry is improper as there is no active dispute. He adds that with the MTPSC's present view, all that a party needs to do to take a matter away from MTPSC purview is to trigger a contract or amendment controversy. This interpretation of the scope of the MTPSC's authority, however, is improper. As the court concluded, the MTPSC does not have jurisdiction over executed agreements. In addition, the MTPSC's consideration of this issue raises the sort of controversy over the meaning of contract terms that the MTPSC is advised would strip it of jurisdiction. Because of the importance of the agreement to

²¹ Based on both a Northwest Power and Conservation Council's (Council's) paper and existing market prices for natural gas, NWE estimates that the energy cost for a combustion turbine is about \$57.10/MWH (\$40.17/MWH if the price of gas were \$3.25). NWE would not provide estimates of costs for the related energy and capacity from the Basin facility. (DR PSC -010) NWE explained that the combustion turbine capacity cost stems from MTPSC orders in D81.2.15. (DR NEI -016) NWE held that REC values must not be added to avoided cost values. (DR PSC -048)

²² NEI held that if capacity charges are reduced for a wind project due to its relative lack of availability, then the price paid to a wind project should also reflect the relative fuel cost price risk posed by a CT. (DR PSC -044)

CELP, involving significant underpayments to CELP from “published PURPA rates” made by NWE/MPC since 1990, any attempt to void the amendment would result in “significant additional payments to CELP,” and may adversely impact NWE’s bankruptcy reorganization effort (pp. 3-5).

Orndorff next explains why the first amendment was executed, including the change in rates. After executing the agreement in 1984, CELP (f/k/a AEM) concluded that the “liquidated damages” provision made financing impossible. CELP accepted a resolution that NWE developed involving the reduction in early contract year payments to levels not requiring security and that involved getting “acceptable assurance from the Commission” that the change would not be a “material” change to the agreement. In 1988, assurance was received in the form of MTPSC (staff) guidance that the agreement would be amended to “delevelize” rates but with guaranteed escalation for the first 15 contract years. As a result, in place of the first year partially levelized energy (3.751¢/kwh) and capacity (\$91.54/kw/yr) rates CELP’s rates began at 2.222¢/kwh and \$55.94/kw/yr. (DR PSC -020(b)) The MTPSC authorized the recovery of CELP’s reduced rates in numerous QFLT rate filings including D91.6.24. He notes that NWE confirmed the existence of the first amendment to the MTPSC and that NWE assured CELP of the validity of the first amendment. Further assurance of the first amendment’s validity was provided by NWE. CELP has included the amendment in filings with the MTPSC, including in D91.4.15. Rate approvals each year since 1990 have been based upon reduced rates in the first amendment. Orndorff adds that the MTPSC never approved the terms of the 1984 AEM-MPC agreement (pp. 6-8).

Orndorff also addressed the savings associated with the amended agreement. He estimates that the ratepayers saved over \$57 million, from “published QF rates” available to CELP.²³ (p. 8) He testified that although the first amendment freed NWE from any refund obligation and freed CELP from any security fund obligation, this does not mean that NWE would not have a \$57 million obligation under the first amendment if it terminated the agreement. If CELP had received levelized payments from day one, it

²³ Because in the early years revenues were reduced by \$57 million CELP is required to have higher rates in later years. (DR PSC -019(a))

would have been overpaid in the early years and the amount escrowed by means of the security fund obligation in the case that CELP did not perform for the contract term. If CELP had received the levelized payment stream and performed, then NWE must refund the security funds. (p. 9) As ratepayers benefited in the early years, for CELP to remain “whole” it must receive the over payments in the “out years.” (pp. 8-9)

Orndorff also testified on the “out of market payments” for QFs that are contained in the Stipulation approved by the MTPSC in D97.7.90. He notes that NWE used (John Leland’s estimate of QF stranded costs) contract payments based upon the first amendment’s rates to compute \$663 million in out-of-market QF costs (p. 10).²⁴

In contrast to NWE’s response to MTPSC staff data requests, Orndorff held that the above testimony is much more accurate. He made three comments about NWE’s responses (pp. 10-12). First, he finds that NWE’s response to DR PSC -014(b) was inaccurate as the CELP amendment was, in part, needed to acquire water rights (p. 10) and to obtain financing. Second, in regard to DR PSC -015(d), whereas NWE suggested that energy production in excess of the 306,600 MWH/year maximum would be paid a negotiated rate he notes that, notwithstanding the court order, there no negotiations occurred. He provides a letter sent to NWE in which CELP did agree to “market pricing.” The most appropriate basis for market prices would be Mid-C rates plus the BPA wheeling and line losses to NWE’s service area although the price that NWE would avoid should be the market price that CELP receives. (DR PSC -021(b)) However, CELP has no opinion on what the relationship should be between STPP and QFLT as the spot market price for power is not sufficient to obtain equity or debt financing. Long term fixed rates are essential (DR PSC -022).

Third, in regard to DR PSC -017, Orndorff disagrees with NWE’s estimate (D97.7.90) of \$1.23 billion in out-of-market QF costs. (pp. 11-12) He disagrees because the estimate ran from 1998 to 2032 and is based upon assumed market prices of 2.225¢/kwh. This assumption is not historically accurate nor does it reflect actual market costs for long-term resources which would be required in the portfolio to replace QF

²⁴ NEI commented that NWE did not incorporate the value of its existing QF portfolio during the times when QFs provided energy at substantial discounts to the market. (DR PSC -032(d))

contracts. It is historically inaccurate as the market costs from 1998 to 2002 were enormously higher. At a minimum, the NWE attachment, “WAP-E” provided in a data response (DR PSC -017(a)), should be updated for actual market prices from 1998-2004 to determine if the QF contracts are out of market.²⁵ With an appropriate update, pricing should reflect the replacement cost of a long-term resource. It should reflect the replacement cost because 2.225¢/kwh is an artificially low price offered by the buyer in a generation sale and is not a market price by which QF contract values should be measured. He adds that comparing actual market pricing for new equivalent resources is the only means to access an ever changing out of market analysis as market pricing changes every year over the term of any QF contract. (pp. 11-12) Orndorff suggests that long-term forecasts of market prices are inaccurate as the only assurance that anyone can offer with a long-term forecast to 2032 is that such a forecast will be wrong.

As for NWE’s Electric Default Supply Plan of January 2004 (Plan) Orndorff mentions that NWE may seek to renegotiate or reject, in bankruptcy, its QF contracts. In response, he testified that neither YELP nor CELP will willingly renegotiate their existing contracts which would reduce cash flow and jeopardize lender/partner approval. He adds that given the bankruptcy of YELP’s own contractor, YELP itself is in precarious financial health.

Orndorff does not believe that NWE could successfully reject the existing QF contracts. Even though the test to approve contract rejection is the “business judgment” test, courts will also consider if rejection might have a disproportionate, large and

²⁵ The request and NWE’s response to DR PSC -017(a) are as follows:

Request: *First, please describe the specific basis for “out of market” costs that was the basis of MPC’s estimate(s) in D97.7.90. The description must explain how MPC estimated its alternative cost and it must describe what the basis was of the alternative cost estimate that MPC supported. Did, for example, the estimate use: 1) “opportunity costs,” 2) regional energy and capacity costs, or 3) some other source for alternative costs that enabled it to conclude that the QF contract prices were out of market*

Response: The out of market costs are the difference between the expected QF costs and the market value of the power. The market forecast was based on three components. From 1998 to 2002 the price is based on the PPL Mt buyback rate, from 2002 to 2007 the price was based on responses to NWE’s RFP for baseload power from its Default Supply Portfolio (specifically the Duke contract), and from 2007 on the price was increased at the projected rate of inflation. Further information is available from the D97.7.90 record.

harmful impact on the non-debtor contract party. Orndorff testified that NWE is unlikely to meet the test for 3 reasons: 1) it will not likely benefit the estate; 2) damage claims may dilute creditor recoveries and 3) the likely impact on NWE's rates would not enhance its reorganized value. In addition, NWE's obligation to purchase from QFs resulted from compliance with state laws (§69-3-601 M.C.A.) and MTPSC orders.

Orndorff testified that QF contract rejection will impact NWE's consumer rates as any out-of-market value that NWE alleges (in response to DR PSC-017) will become an additional significant unsecured creditor claim. The suggested \$1.23 billion out-of-market pricing would severely impact the existing \$1.8 billion of unsecured creditors' total recoveries and likely jeopardize the approval of any plan of reorganization absent a rate increase to make unsecured creditors indifferent to including the QF unsecured creditor claims (p. 14). Although NWE's position is that any contract rejection will reduce annual ratepayer payments for QF resources by \$25 million, Orndorff adds that the MTPSC and NWE did not agree to reduce stipulated payments to NWE for the loss of QF resources; thus, the worst outcome for ratepayers and the best outcome for NWE's creditors/shareholders would be for NWE to collect the annual \$25 million and eliminate and replace all QF resources with, for example, a new rate, one that is based upon a NWE gas project. (pp. 13-14)

Based on an analysis of market pricing for new long-term resources, Orndorff concludes that YELP and CELP are not out-of-market resources. His analysis assumed that QF contracts, even if rejected, remain a ratepayer cost and that no long-term resource can be built for less than \$.05/kwh.²⁶ He adds that a project cannot achieve lender financing absent "a minimum 1.5 debt service coverage after project operating expenses" (debt service requires payment of both interest and principal). He testifies that NWE has consistently made less than full payments required under existing contracts. He also testified that CELP, YELP and another QF have brought lawsuits in the Delaware court and noted that unless NWE corrected its commercial behavior with independent energy

²⁶ His \$.05/kwh estimate is based on project development experience in Montana. Only a fixed price, not a fluctuating market price, will provide the necessary assurances for debt service and equity returns. (DR PSC -026)

suppliers that such “conduct” will further frustrate financing and will result in arguments by NWE that it must build its own project. (p. 15).

Orndorff recommends that QF contracts be “promptly assumed” as there is no viable alternative to acquire cheaper resources without impacting the reorganization.²⁷ As delay will only result in a weaker successor company and higher ratepayer costs, NWE’s filed plan should be reviewed and implemented as soon as practicable if NWE is to remain a “separate entity.” (pp. 15-16)

Navitas (NEI) Testimony: Christopher Moore

On March 4, 2004, Christopher Moore submitted testimony on behalf of NEI. The purpose of Moore’s testimony is to describe NEI’s view of NWE’s avoided costs as they relate to wind projects.

Moore asserts that there are several problems with the QF-1 tariff. First, its availability is arbitrarily capped at a project size of 3 MW. NEI believes the appropriate cap is 80 MW, which is contained in FERC rules implementing PURPA. Moore testifies that economies of scale enable larger QF projects to produce energy more economically and offer utilities lower prices, which, in turn, saves ratepayers on the cost of power. Everyone is better off with larger QFs, according to Moore. He asserts there is no real basis for the PSC’s 3 MW limitation.

Second, Moore asserts that the rate of \$32.75/MWH was not established based on a thorough analysis of NWE’s avoided costs, and that NWE’s proposal in this proceeding still does not provide a rational basis for an avoided cost rate for new QF purchases by NWE. Moore states that the QF-1 rate should reflect an objective benchmark for avoided costs. According to Moore, this MTPSC appears to have tried to chill QF development by: 1) setting avoided cost rates at an artificially low level (less than \$20/MWH); 2) constraining QFs to short-term contracts (10 years or less); 3) minimizing

²⁷ By “promptly assumed,” CELP means that the “Plan of Reorganization” must necessarily deal with the treatment of executory contracts and “Assumption simply means executory contracts in existence prior to the bankruptcy proceeding should continue after the reorganization of NWE as if the bankruptcy did not occur.” (DR PSC - 027)

project size to eliminate the benefits of economies of scale; and 4) approving QF rates that are subject to sudden change or elimination (i.e., tying it to state or federal legislation). In order to promote QF development, Moore recommends making avoided cost rates and their calculation transparent and offering QFs contracts for at least ten to fifteen years.

Moore disagrees with NWE's proposal for determining a QF-1 rate. He believes NWE's approach inappropriately relies on historic costs when it should focus on forward-looking marginal and incremental costs.²⁸ Short-term transactions should not be ignored if they form the basis for long-term power supply. The MTPSC should exclude "sweetheart generation contracts" that do not reflect avoided costs from the calculation of the QF-1 rate. Finally, contracts should be weighted by significant time period, e.g., summer, winter, peak, off-peak.

Moore particularly disagrees with NWE's use of the annual cost of a combustion turbine (CT) as a proxy for the capacity component of the QF-1 rate. Moore asserts that using a 40 MW CT is improper because economies of scale will make a large CT more cost effective. He says the use of an 85% capacity factor is inappropriate for a firming resource and asserts NWE failed to reflect the ability to use a CT to off-set ancillary services costs, such as balancing, or avoid short-term purchases. Moore says it is difficult to get an "apples-to-apples" comparison of a CT and a non-peaking resource like wind without comparing fuel costs; wind is capital intensive, but has no fuel cost, while CTs are less capital intensive but have high fuel costs.

Moore asserts that NWE has failed to recognize the value of QFs as a market hedge. He believes the calculation of NWE's avoided cost rates should reflect the added value of a QF contract to the utility and ratepayers during periods when market energy prices are extremely high. For example, Moore criticizes NWE for not considering the value of its existing QF portfolio during the energy market crisis of 2000-2001.

Moore recommends the approach used by Commonwealth Edison to establish rates for QFs. Exhibit 1 to Moore's testimony provides a copy of certain statutes of the

²⁸ If the MTPSC bases avoided costs on historical costs, then all historical costs including in-market payments for QF power that are in the default supply must be included. (DR PSC -033(c))

state of Illinois governing the purchase and sale of electric energy from cogeneration and small power production facilities. According to Moore, Commonwealth Edison's QF rates are based on long-term power supply contracts. The rates fluctuate as existing contracts expire and new contracts replace them. Moore states that a benefit of this approach is that the QF rates are never substantially out of market.

Finally, on the issue of renewable energy credits, Moore asserts that RECs can be included in the avoided cost calculation if the cost basis for the avoided cost calculation reflects the transfer of RECs in underlying contracts.²⁹

Two Dot Wind, LLC (TDW) Testimony: Van Jamison

On March 4, 2004, Van Jamison filed testimony on behalf of TDW. His testimony focused on RECs as they relate to transactions between a utility and a QF.

Jamison begins by explaining that there is not an established standard for defining RECs, which are also referred to as either green tags or renewable energy certificates. Generally, according to Jamison, a REC "is a collection of all environmental and social attributes internalized in a unit of only 'renewable' generation which has been separated from the underlying electricity product to be sold independently as a discrete, tradable instrument."³⁰ The concept of RECs is meaningless in the context of power markets. However, within power markets products that include all the attributes underlying RECs may also be purchased and sold as "green power."³¹ Green power is often marketed as a distinct, higher-value power product.

²⁹ If the avoided cost price includes the incremental value of the RECs, then the RECs should be included with the QF power purchases. (DR PSC -031(e)) If the avoided cost is calculated based on a resource or resources that provide RECs along with energy, then the avoided cost can be said to incorporate the value of RECs. DR PSC -038(b),(d)

³⁰ The term "attributes," as used in defining RECs, refers to environmental and social benefits that exceed established minimum environmental and social standards, permitting and other requirements. These additional benefits are the basis of a REC's value. (DR PSC -054(b)). The primary attributes embodied within RECs are related to air quality, water quality and waste reduction advantages that renewable resources have compared to other types of generation. (DR PSC -055)

³¹ According to Jamison, whether renewable electricity supplies are purchased as bundled "green power," or RECs are purchased separately and combined with non-renewable electricity products, the resulting product is "green" or renewable. (DR PSC -055(d))

Jamison highlights what he sees as an inconsistency in the way that NWE offers its optional E+ green power service to retail customers and the way that NWE approaches negotiations with renewable QFs. NWE's E+ green program allows customers who want to support new renewable energy resources in the Northwest to pay a premium of \$2.00 per month for each 100 kwh block of renewable energy attributes (\$20/MWH) in addition to all other electricity supply and delivery charges. Each \$2.00 premium buys the environmental benefits associated with 100 kwh of renewable energy being generated in the Northwest and Wyoming. Jamison states that a fundamental purpose of RECs is to give renewable energy project developers a co-product to sell in addition to power, thereby encouraging them to build additional projects. According to Jamison, at the same time NWE is asking retail customers to pay a premium to support renewable projects, it is trying to obtain RECs from renewable QFs without compensation at its avoided cost. Jamison asserts this asymmetric treatment of "green" values distorts and compromises power markets.

Jamison criticized NWE for ignoring the price signals being conveyed through green power products and RECs, given that the company has specifically accounted for other material differences in the power products QFs provide, for example capacity factors. Jamison does not recommend, however, requiring NWE to pay a higher avoided cost rate to renewable QFs to account for the price signals conveyed in green power markets and markets for RECs. Rather, NWE should be free to decide whether or not it wants to buy the renewable attributes from renewable QFs. NWE should not be allowed to refuse to enter an agreement with a renewable QF unless the QF "hands over" the RECs without compensation. Jamison suggests proper compensation for renewable attributes could be in the range of \$4.00 to \$7.00/MWH.

Jamison acknowledges that given the immature nature of the market it is difficult to track the trading and use of RECs.³² There are not consistent standards for what is

³² Jamison stated that presently there is no organized marketplace where RECs or their equivalents are traded within the Western Electricity Coordinating Council boundaries, although many marketers offer "green power," RECs and other renewable energy products. (DR PSC -054(d)) Markets for standard power products such as energy, capacity and ancillary services are more developed, in part because these markets are

renewable and, therefore, what RECs represent. Because tracking systems are not well developed, double counting plagues the system, according to Jamison. However, numerous groups are working to address these market design issues, including a work group under the Western Governor's Association.

Ultimately, Jamison recommends that the MTPSC determine that resource attributes associated with a QF belong to the QF and, if there is any exchange involving those attributes, those exchanges are separate transactions that are not covered within PSC-approved avoided cost tariffs.³³ Jamison recommends that the MTPSC determine that NWE only obtains title to energy and capacity purchased pursuant to QF tariffs.³⁴

NWE Supplemental Additional Issue Testimony: Mark Stauffer

On March 31, 2004 Stauffer filed supplemental testimony that addressed REC issues. NWE's supplemental REC testimony was received after NEI and TDW testified on this issue. He testified that RECs are separate products, distinguishable from power purchased through QF contracts or contracts that result from competitive solicitations. In general, Stauffer agrees with the way TDW witness Jamison characterized RECs (see summary of TDW testimony above). Stauffer asserts the following in his testimony: 1) the market for RECs in the Pacific Northwest is in its infancy; 2) distribution utilities will likely be the primary intermediary between renewable energy generators and retail consumers who want to buy renewable energy; 3) the disposition of RECs associated with renewable QF projects should be determined by negotiation between willing buyers

more broadly regulated. (DR PSC -058) He declined to answer the question of whether any state or federal laws or rules would preclude a prospective QF from obtaining QF designation if it had previously sold its RECs.

³³ When asked how a QF would market its resource attributes, Jamison stated such attributes could be sold to brokers or marketers who would in turn resell them. He added that a QF could auction RECs or contract known REC traders. (DR PSC -058)

³⁴ He stated that RECs are a commodity separate from the QF-related issued of avoided cost. The PSC should recognize that RECs rightly belong to the project owner until they are voluntarily sold. (DR PSC -054)

and willing sellers; and 4) the avoided cost for power and the market value of RECs should be kept separate because PURPA does not require utilities to purchase RECs.³⁵

Although there is not a mature market for RECs, Stauffer believes that an efficient market will develop that will provide incentives for the development of renewable energy products. NWE currently participates in the REC market.³⁶ He testified that utilities need flexibility to decide what amount of RECs they need and what price they are willing to pay based on the demands of their retail customers. With respect to QFs, he suggests that if NWE and a renewable QF mutually agree on an exchange of RECs, then the transaction should occur. He also asserts that if NWE purchases a green power product from the QF, the avoided cost rate should not be adjusted. Instead, the mutually agreed-upon value for the renewable attributes would be determined separately between the two parties.

Stauffer favors trading RECs in the marketplace for several reasons. First, he does not believe PURPA requires that utilities purchase RECs. According to Stauffer, PURPA requires utilities to purchase power from a QF at a rate that is equal to what the utility would otherwise pay for that power.³⁷ Since a particular QF project may or may not have the ability to obtain RECs, he reasons that the avoided cost of power should be unaffected by the additional REC product. Second, he states that the market will establish equilibrium and prevent distortions in the supply of and demand for RECs. Third, NWE does not know how many RECs it will need to supply the demands of its

³⁵ Stauffer agreed that PURPA explicitly constrains would-be QFs to electricity production methods that either represent an improvement in thermal efficiency compared to conventional generation or embody renewable resource attributes. However, he maintained that a QF wind project is a renewable resource with or without RECs. He also stated that if NWE were required to disclose the fuel source and emissions information related to its resource portfolio, NWE would disclose the renewable attributes of a renewable QF even if the QF sold RECs to another party. (DR PSC -052)

³⁶ NWE's optional E+ green power service allows customers to purchase renewable energy attributes for \$2.00/100 kwh block. NWE purchases RECs from the Bonneville Environmental Foundation in order to obtain the renewable attributes sold to retail customers through the E+ green program.

³⁷ NEI also agreed that RECs should not be included in the avoided energy cost calculation. (DR PSC -036(d))

customers, which, in turn, is a function of the price NWE charges, with PSC approval, for products offered under the E+ green program.

Stauffer rebuts the assertion by TDW that NWE tries to coerce renewable QFs in Montana to transfer the environmental benefits of their projects to NWE without compensation. According to Stauffer, NWE does not require QFs to transfer REC rights to NWE as a condition of any power purchase agreement. NWE has inserted language in proposed contracts with QFs that define the disposition of RECs as a starting point for negotiations. Stauffer asserts that it is essential for any business relationship involving a renewable QF to be clear about which party has rights to the RECs.

Stauffer also disagreed with TDW's assertion that NWE misleads its E+ green customers by coercing RECs from QFs and reselling them to the customers for \$20/MWH. He states that NWE does not obtain any RECs from QFs. The RECs NWE purchases to support the E+ green program come from the Bonneville Environmental Foundation and any incremental revenues NWE receives above the purchase costs are used to promote the program.

NWE Rebuttal Testimony: Mark Stauffer

On April 15, 2004 NWE filed the Rebuttal Testimony of Mark Stauffer. His rebuttal addresses the testimony of NEI's witness Moore. He first identifies two issues on which NWE and NEI disagree. These issues involve QF access to the QF-1 rate and contract length. Whereas NEI holds that large QFs should have access to the QF-1 tariff, NWE would allow access only until such time as QFs can participate in a RFP. Whereas NEI advocates contracts that are of at least 15 years duration, NWE holds that, based on ratepayer indifference, the contract term should reflect the weighted average term of the underlying avoided contracts that are the basis of the rate.³⁸ (pp. 1-2)

³⁸ In response to a question of why NWE proposed to use a "weighted average," given that the incremental – avoided – cost will exceed the average, NWE responded that its proposal is to use the weighted average of marginal contracts (e.g., baseload, peaking), not embedded contracts, and that therefore the intent of marginal, or avoided costs, is maintained. (DR PSC -080(d))

Stauffer expands on these two issues. He holds that QFs have adequate access to regional power markets, as evident from Idaho Power's recent purchase of 9 MWs of wind in Great Falls and Avista's recent purchase of 35 MWs of wind. These examples demonstrate the opportunities that producers have to sell their power in the regional marketplace.³⁹ In addition, all large transmission providers have open access tariffs. Still, NWE will pay large QFs the QF-1 rate until the next RFP is complete. If in the next RFP a QF is deemed to not be competitive, it would not be eligible for another QF-1 contract but could submit a bid in any future RFP.

To award a large QF a QF-1 contract after it failed to submit a competitive bid would undermine the RFP process, violate the avoided cost rules and be a cost burden for NWE's ratepayers.⁴⁰ (pp. 2, 3) It would burden ratepayers because a QF that knew it could receive the QF-1 rate would displace RFP bidders by taking the rate. Any incentive to participate in the RFP is, as a result, removed. If the QF participated, it would have an incentive to bid high because of the QF-1 safeguard. Both reasons point to how the efficiency of the competitive RFP process would be compromised. (p. 3)

Stauffer next addressed Moore's testimony regarding the 3 MW threshold.⁴¹ While Moore favors an 80 MW limit in place of the 3 MW limit, according to Stauffer

³⁹ NEI expressed concern, due to the volatility of a market index and because market rates do not reflect long-term marginal costs, with tying avoided cost rates to any market value unless the alternative features a hedge mechanism. (DR PSC -032(c), -037(d)) NEI commented that avoided costs should reflect the opportunity cost principle. (DR PSC -033(a)) NWE asserted to provide estimates of sales and purchase prices. (DR PSC -070) NWE asserted that its response to DR PSC -070 that contains opportunity sales and purchase values were transactions that were not encumbered by transmission constraints. (DR PSC -083(d)) NWE further added that any entity that has a firm point-to-point transmission contract with unused available capacity has priority to use the unused portion of its contract. (DR PSC -083(e)) In the case of the Mid-C index, NWE would subtract \$3/mwh, reflective of NWE's belief that energy in Montana is discounted relative to the Mid-C due to transmission costs and in order to account for the sharing of transmission cost avoidance. (DR PSC -087(c)) NWE filed on July 2, 2004 its late-filed response to DR PSC -087.

⁴⁰ With respect to the violation of rules, NWE noted that consumer indifference would be violated to the extent an inefficient RFP process produced avoided cost rates higher than they otherwise would be. (DR PSC -068)

⁴¹ NWE asserted it is the source of the 3 MW limit in the QF-1 tariff. (DR PSC -068(d))

Moore provides no evidence that a 3 MW limit is irrational. As for Moore's suggestion that large QFs offer economies of scale and therefore "ratepayers save on the power produced," he responds that there is no difference to ratepayers in terms of the rate that is paid. He adds that large QFs are able, because of their size, to negotiate with numerous potential buyers and therefore they do not need the same access to "a" QF-1 rate that a small QF needs.⁴² Both scale economies and open transmission access provide large QFs the ability to compete effectively in the region's RFPs. (pp. 3, 4)

Stauffer finds little difference in what NWE is proposing and Moore's proposal to use ComEd's approach. Just as ComEd's rate fluctuates somewhat as contracts roll in and out, NWE proposes to use the "weighted average price of the marginal contracts" that are the basis of serving NWE's default supply load (DSL). Rates will change as contracts are added or deleted from the portfolio. He added that both the "weighted average cost" and the term of the contracts in NWE's default supply portfolio (DSP) should be the basis of the QF-1 rate.⁴³ He acknowledged that Moore may disagree with the "weighted average" term of the rates but notes that it appears consistent "with the basic concept" (an apparent reference to ComEd's rate). He added that, in terms of maintaining ratepayer indifference, the term of contract is as important to a contract as the price and quantity terms: it is essential that the "term" offered be based on the same resources as the price and quantity. (pp. 4, 5)

Stauffer rebuts Moore's contention that NWE has not provided a rational basis for the actual avoided cost rate. As the Default Supply Utility (DSU) is 100 percent reliant on the market for all "marginal purchases," these purchases are the basis for avoided costs. (p. 5)

⁴² NWE elaborated on the size threshold that separates large from small QFs and why small QFs may not have access to regional power markets. (DR PSC -066(e))

⁴³ In response to DR PSC -069(d) NWE revised this sentence to insert "marginal" before the word contracts. In addition, there would be no levelization unless in bids. (DR PSC -070(a)) The method of weighting is also explained. (DR PSC -070(b)) By "term" NWE appears to mean a longer than one month contract. (DR PSC -083)

Because NWE's avoided cost rate relies on marginal purchases, it no longer relies on "system lambda," utility built resources or theoretical resources.⁴⁴ Nor does it rely on what Moore labels a "market hedge value," that Stauffer correlates with "opportunity sales."⁴⁵ He finds "potential opportunity sales," especially Moore's suggestion to pay QFs the higher of the avoided cost rate or the market, irrelevant to the avoided cost rate calculation.⁴⁶ He labeled Moore's proposal an "opportunistic" one as, if implemented, the credit for any excess power that is sold in the market would go to the QF, and not to ratepayers. If the QF wishes to speculate, it should not sell power to NWE. NWE seeks

⁴⁴ NWE admitted that the basis for the STPP rate is system lambda and a capacity payment. (DR PSC -071) Whereas the interim STPP rate was \$.01128/kwh NWE admits that, based upon its response to DR PSC -070(d),(e), the cost of resources that NWE purchased as short-term transactions amounted to \$.032137/kwh. (DR PSC -084(c))

⁴⁵ NWE found blatantly opportunistic Moore's proposal to pay QFs the higher of the spot market or the avoided long-term contract. (DR PSC -071(c)) Any excess amounts of energy and, or, capacity that NWE must purchase is sold into the market, as the market value is what the power is worth, with the proceeds going to DSP (retail) customers; but, contractual arrangements may limit such sales. (DR PSC -071, -073, -073 and -084(d))

⁴⁶ NWE explained that it has supply contracts that involve market purchases with terms ranging from one hour to 90 days. (see both DR NEI -004(a) and NEI's response to DR PSC -032(c)) In explaining why NWE does not combine the fuel cost with a combustion turbine's capacity cost, NWE explained that "Most likely is that the running cost will be displaced with opportunity purchases at the Mid-C, so from an operational perspective the CT capital costs reflect the capacity cost of operating reserves for times of system peaking, or marginal peaking costs." (DR NEI -017(e)) NWE does not appear to believe that there is need for consistency between the choice of capacity and the choice of energy. (DR NEI -018) NWE adds that ("...it is fair to adjust capacity to account for intermittent resources such as wind, but not to compare fuel input as a component of the overall cost of the project on an energy rate basis." (DR NEI -019) Since the avoided cost basis is not a CT it would violate the basic purpose of PURPA if the QF-1 rate reflected the cost to operate a CT. (DR NEI -020) NWE does not believe opportunity sales values belong in the QF rate. QFs can market their own power, up to 8760kwh/kw per year, but at a cost of \$40.88/kw/yr for point-to-point transmission and if transmission capacity is available. There are no added transmission charges so long as the customer remains within the service definitions in the open access tariff. However, interconnect charges will be assessed if the QF connects directly to NWE's system. (DR PSC -066(b) and PSC -081(c),(d)) If QFs wish to reach markets beyond the entities with which it has interconnection (BPA, IPC, Avista, WAPA and PacifiCorp), then they may incur additional transmission costs. QFs have the same opportunities to make sales in the regional markets in which NWE has sales opportunities. (DR PSC -067)

to avoid the excessive risk associated with the erratic spot market and will not sign a contract with a provision as suggested by Moore. (pp. 5, 6)

Stauffer explained when the avoided cost rate paid to a QF should deviate from the QF-1 rate. One occasion is when NWE purchases power in excess of its DSL obligation. If a QF demands a contract when NWE is in resource balance, then the QF should receive the QF rate if the power is used for DSL consumption. If the power provided exceeds NWE's needs, the QF should be paid the lower of the QF rate or the market (rate). (pp 6, 7) To fulfill its DSU obligation, Stauffer adds that NWE must be able to rely upon providers of power.

Stauffer testified that it is bad public policy and would violate the fundamental premise of PURPA, which is ratepayer indifference, if NWE must purchase "long-term power" in excess of its DSL needs. Requiring NWE to "acquire excess resource," if NWE would not otherwise purchase added resources, would transfer risk from the QF to NWE and its ratepayers and potentially create "stranded costs." In such a case, the appropriate QF-1 rate is zero. In addition, there is no value to the DSU in buying long-term power to, in turn, resell the power in the competitive market. In addition, "large QFs" have "equal access" to the same markets as NWE can access and at equivalent transmission costs. In this regard, only those QFs "that NWE is forced to acquire" and that are in excess of need would be "on the margin." QFs that allow NWE to avoid other purchases should receive the QF-1 rate.

Stauffer rebuts Moore's criticism that NWE inconsistently uses "historic costs" while holding that the "in market component of QF contracts should be in the portfolio costs." He explained that the contract costs that NWE proposed to use are the most recent marginal contracts which will be updated once NWE completes its current RFP. In contrast, the QF contracts that Moore references are 1980s vintage. Whereas the recent contracts are RFP based, the old QF contracts contain no useful avoided cost information as they were administratively determined and unfortunately reflect rates that are severely divorced from any reasonable market value. Thus, Moore's suggested "in market" valuation is simply a backdoor computation of avoided costs that is based upon his conjecture of market prices. (p. 8)

Nor does Moore's proposal take into account NWE's unique DSU structure. Whereas Moore's proposal is more consistent with a traditionally structured vertically integrated utility that is in the generation business, NWE is not competing to serve its DSL.⁴⁷ Instead, NWE seeks competitors to submit bids to serve that load. PURPA's original purpose was to allow QFs an equal opportunity, relative to the "native utility," to serve loads. "Large QFs" have, via the RFP process, an equal opportunity along with all other providers to serve NWE's loads. The QF-1 rate gives "QFs" a second opportunity, that no other provider receives, which is to be paid the QF-1 rate until the QF participates in an RFP. This opportunity more than meets PURPA's requirements. (p. 8)

Stauffer rebuts Moore's accusation that NWE ducked a question regarding NWE's default supply plans. At present, NWE is rebuilding its DSP with new contracts that will replace existing contracts. In the RFP that it expects to complete, NWE will seek bids for each of dispatched, base load and post-2007 replacement power. Until this RFP is complete and NWE has had an opportunity to analyze the proposals, NWE would base the present "QF rate" on the most recent contracts in the existing DSP, after which time it will be able to compute a new "QF-1" rate. He added that NEI will have an opportunity to participate in this RFP.

Stauffer next responds to and rebuts Moore's testimony on NWE's use of a combustion turbine to "differentiate" the total QF rate into energy and capacity.⁴⁸ He testified that the CT has been used regularly by the industry for this purpose and its use is a corollary to the Commission's Base-Peak method.⁴⁹ In rebutting Moore's concern over

⁴⁷ NWE admits that Section 210 of PURPA is not limited to vertically integrated utilities. (DR PSC -074)

⁴⁸ NEI supports separate energy and capacity rates adding that demand charges could be implicitly included in the STPP. (DR PSC -034(d), -035(a))

⁴⁹ NWE referenced MPSC Order No. 4865 (FOF 31) to support its testimony that its proposal is a corollary to the MTPSC's base peak method. In its current application, NWE substitutes the "total market costs" for that of a base load coal unit. NWE adds that its attachment to PSC -008(e) is the implementation of "Order 5017 base/peak rates." (DR PSC -074(e)) NWE's response to DR PSC -086(a) asserts that Stauffer's corollary has no mathematical connect to the underpinning base-peak approach but is simply a matter of logic. In response to DR PSC -086(b), clarifying prior responses to PSC -074(e) and -075(a), NWE asserts to simplify the MPSC's complex formula with the result

NWE's use of an 85 percent capacity factor, he asserts that NWE used this factor to spread the capacity charge over the load served. This is necessary because the DSP's customers are all firm energy customers and should therefore pay a portion of the capacity charge. Since the CT is not likely to run during regional average water conditions, with Moore's logic the capacity factor used to differentiate the CT's costs would be linked implicitly to the actual running of the CT, with the capacity rate reflecting the entire QF-1 rate and an energy rate of zero. He finds this result inappropriate. (pp. 9, 10)

Stauffer adds that following the "allocation" to capacity and energy both seasonal and diurnal allocations are needed.⁵⁰ Since NWE is no longer a vertically integrated utility the traditional "loss of load" analysis is no longer available for this purpose. NWE is hopeful that responses to its RFP will provide useful data to both allocate the "new QF-1" rate between capacity and energy and to diurnal and seasonal time periods. (p. 10)

Stauffer asserts that Moore does not offer an alternative means of allocating the total rate into capacity and energy. He adds that it is not in the interest of an intermittent resource provider to have a capacity component in the rate. As capacity is for the contracted provision of energy and is essential to serve load, and since wind power does not provide such a guarantee, he is not surprised by NEI's suggestion that capacity is an irrelevant product. He states Moore's proposal, that "demand charges would be implicit in the time sensitive nature of rates," allocates the total rate diurnally and seasonally without differentiating the two products. The result is that NEI would be paid for firm

that the energy rate equals the "total market costs of the DSP" instead of the cost for a base load unit. NWE adds, "Since the total market price replaces the total base load costs, and the supplied NPCC costs replace the peaker costs, the basic base/peak approach is retained with all costs included, but significantly simplified." NWE has also advocated the exclusion of peaker running costs on grounds that in most years the region has better than average water conditions. (DR PSC -086(b))

⁵⁰ NWE added that the RFP was not intended to garner information that would allow for the "allocating" (sic) of the QF-1 rate between energy and capacity; NWE interprets the requirement for an STPP capacity payment to be premised upon avoidable capacity costs. NWE also added that because QF power production is metered on an hourly basis capacity rates may vary on a diurnal or seasonal basis. (DR PSC -076) In its proposal, NWE intended to view each QF on an individual basis and does not appear to recognize the aggregate capacity value of various QFs. (DR PSC -077)

capacity that it does not provide. He asserts that NWE must know how much capacity it has available to serve its DSL and since NWE acquires capacity in its DSP contracts, NWE must have a capacity rate to accurately reflect this product (p. 11). NWE will require QFs to provide capacity at “agreed time intervals” and if they fail to provide the capacity, NWE will not pay them as NWE must then pay someone else to provide capacity.

In regard to NWE’s use of the Northwest Power and Conservation Council’s (Council’s) CT estimate as the basis for its “demand/energy allocation,” Stauffer disagreed with Moore’s characterization that the Council’s estimates are “wildly inaccurate.” Stauffer restates that NWE does not intend to develop resources and instead will rely on reputable sources, such as the Council, for proxy numbers. In this regard, he finds the Council’s 2004 estimate more accurate than Moore’s 1994 estimate (pp. 10, 11).

Finally, Stauffer testified, without elaboration, that Moore’s testimony is unclear on other issues and that NWE cannot establish NEI’s position. (p. 2)

CELP Direct Testimony: Richard Lauckhart

On January 24, 2006 CELP filed the direct testimony Mr. Richard Lauckhart. Lauckhart addressed issues related to certain of NWE’s avoided costs for the 2005-06 contract year.⁵¹ His testimony specifically addressed two issues, the failure of NWE to use the “incremental costs of capital including tax effect” and “other escalators” involving indexes and coal costs.⁵² He also comments on ratepayer impacts.

⁵¹ He asserts that the basis of CELP’s rates is MTPSC dockets “83.1.15 and 83.1.2” (sic). DR PSC -109. Apparently, CELP’s contract with NWE only references D83.1.2, Order 5017 and 5017a; any suggested reference to D81.2.15/Order 4865 is only by reference of orders in D83.1.2. DR PSC -111(c) His testimony did not cover NWE’s September 28, 2005 amendment proposals. On January 27, 2006, CELP filed an Errata correcting the page labeled Attachment 3, changing the title to NWE embedded cost of debt adopted in Order 6271c. In a follow up data response, CELP explained which rate it selected out of D83.1.2 and how that rate was modified in the First amendment. DR PSC -133(a)

⁵² He asserts to explain how the contract that CELP has with NWE (“first amendment”) addressed each issue raised in his testimony; the First Amendment establishes how the rates are to be computed. DR PSC -111(b) In a follow up data response (DR PSC -135(d)), CELP explained why the contract it has makes the rate issues MTPSC’s

Lauckhart urges the MTPSC to address NWE's failure to follow the MTPSC's direction to use the incremental cost of capital (ICC) when computing avoided costs that the MTPSC has consistently required (Orders 4865, *et seq.*, and 5017) be used.⁵³ He explained that the theoretical difference between the ICC and the embedded cost of capital (ECC) is the cost of debt, but added that there can also be a difference in the ICC and the ECC for the equity component. Whereas the ECC for debt reflects payments that a utility must make to bondholders, the ICC for debt is what would have to be paid if new debt was sold in current markets (pp. 3-4). Whereas there should be no difference in the ICC and the ECC for equity in practice the two may diverge, especially if significant time has passed or if major financial events occurred. Lauckhart expects the ICC to exceed the ECC mainly because of the financial decisions by firms to minimize debt costs and second because NWE is a risky entity now compared to when the MTPSC last authorized its cost of capital in 2001. The cost of equity will rise with the increased risk.

Lauckhart testified that NWE used the adopted capital structure, and costs of various types of capital, contained in the MTPSC's May 9, 2001 order (No. 6271c in D2000.8.113). He adds that in "the Filing's workpapers," NWE labeled these capital costs as "marginal" costs, a term that he equates with "incremental" costs. He also added that NWE most definitely used an ECC, which is neither a marginal nor an ICC concept, and NWE used inputs that do not reflect the contract year capital market. He reasoned

jurisdiction: CELP and MPC agreed to abide by the MPSC's determination based on D83.1.2 orders.

⁵³ He cited to the MTPSC Order 4865: "Capital Costs are to be annualized by applying the companies' overall incremental costs of capital including tax effect – not embedded cost of capital – and shall be updated annually to reflect the contract year capital market." (para. 34). He admits to not know how long the alleged error has existed. Although it appears pervasive in these three consolidated dockets this is the first time that CELP has alleged such an error. In any case, he explained that the error does not affect the computation of the partially escalating rates. (DR PSC -109) In a follow up data response (DR PSC -135(c)), CELP explained that "partially levelized energy rate" is defined by the first amendment; after year 16, there is an "escalating energy portion of the partially levelized rate." In response to DR PSC -137(a), CELP provided the rates that it was paid in the first 15 years.

that NWE has used an ECC because that was what the MTPSC adopted in Order 6271c.⁵⁴ That cost of equity is not now incremental although it may have been in 2001. The MTPSC's findings in Order 6271c are not a current assessment of NWE's financial condition. As the MTPSC said in its Order 6271c (para 83), MPC is not a much higher risk company that needs a much higher rate of return (the MTPSC authorized a 10.75% cost of common capital). He criticized NWE for not using a cost of equity that reflects "the contract year capital market" (Order 4865, para 34).

Instead, Lauckhart recommends a 10.65% cost of capital (made up of 13.15% equity costs and 8.15% debt costs, each weighted 50/50.)⁵⁵ He proposed that NWE use unweighted incremental costs of equity and debt as that is what SCE (an apparent reference to Southern California Edison) must pay to finance new projects (p. 7). He favors the 50/50 equity/debt capital structure because there should be no preferred stock or QUIPS in NWE's capital structure and because NWE's capital structure should be changed to reflect current values (per NWE's 10-Q filed September 2005 with the SEC). In support, he holds that NWE has suggested that its ICC for debt exceeds its ECC for debt. He proposed a higher ICC of debt of 8.15% because SCE has better access now than NWE does (at 7.75% in September 2005) to capital markets. He adds that if NWE's debt cost experienced the same increase, from 9/2005 to 1/2006, as did the yield on 10-Year Treasury Notes, that rose from 4.19% to 4.38%, then NWE's debt cost would now be 8.10%. He estimates that the changes he proposed would increase NWE's avoided capacity cost from \$65.765/kw/yr to \$79.425/kw/yr. The cost of energy would increase from \$.042415/kwh to \$.050038/kwh.

Lauckhart further testified that NWE needs to include the "tax effect" in the cost of capital. (p. 9-10) This would be achieved by grossing up the ICC for equity to reflect the added revenues that NWE needs to pay taxes on its return on equity. After accounting for these impacts, the ICC of equity (after-tax) of 13.15% rises to 21.37% and the total ICC increases from 10.65% to 14.759%. He recommends, however, that NWE

⁵⁴ Citing MPC witness Ms. Senechal's testimony supporting a 6.46% embedded debt cost.

⁵⁵ In contrast, NWE proposed: a 10.75% cost of equity, 8.54% COST of QUIPS (Quarterly Income Preferred Stock), a 6.4% cost of preferred and 6.46% debt cost. (p. 7)

implement his proposal in its “next rate filing.”⁵⁶ (p. 12) With CELP’s proposal (corrected) the cost of capacity would rise from \$79.425 to \$107.662/kw/yr and the cost of energy would rise from \$.050038 to \$.065599/kwh. Overall, his corrections would increase the capacity and energy avoided cost payments by roughly 62% and 31% respectively.

Labeled “other escalators,” Lauckhart next identified three measures of changed avoided cost data that NWE should annually update. These include: (1) the GNP-IPD, that NWE used to, in part, annualize capital costs, (2) the Unit Labor Cost (ULC) that NWE used to escalate both capital (construction) cost and Operations and Maintenance costs and, (3) the non-residential fixed investment that NWE used to escalate both capital (construction) cost and Operations and Maintenance costs. (p. 13) NWE should annually update its Colstrip Units 3 and 4 (C 3&4) coal costs that are used to escalate fuel costs.

Lauckhart testified that NWE’s 2005 filing included both proper and improper computations of avoided costs (pp. 13- 16). He believes that NWE used reasonably fresh estimates of federally-published escalators (items 1–3 above), a practice that NWE should continue.⁵⁷ He also believes that NWE correctly computed the annual cost escalators implicit in the GNP-IPD and Non-Residential Fixed Investment. As for errors, he notes that NWE overstated the annual ULC escalation, however minor the consequences may be. He recommends that the MTPSC direct NWE to use the correct annual value of the escalator.

⁵⁶ If there is an error in the cost of capital, he did not support historical rate adjustments. DR PSC -110(a) He added that by “next rate filing” he meant the next occasion on which NWE updates its avoided cost calculations, which will be pursuant to a final order in this Docket. DR PSC -110(c) His references to “updates” and to “this docket” are unclear. In a follow up data response CELP provided contract terms that limits rate adjustments. DR PSC -110(b),(c) In a follow up, CELP also explained that other than interim order, no prior approved rates can be adjusted. CELP believes there are only two interim orders (D2004.6.96 and D2005.6.103). DR PSC -133(c) CELP believes that NWE’s proposed interim adjustments improperly interpret Order 4865’s definition of incremental capital costs and are inconsistent with the First Amendment. DR PSC -133(e)

⁵⁷ This he asserts is consistent with MTPSC order 4865 (para. 33) requiring that all costs be stated in constant contract year dollars, updated each June 1 (pp. 13-14).

As for NWE's coal cost data, Lauckhart testified that it appears NWE did not include severance taxes. (p. 15-17)⁵⁸ The MTPSC should direct NWE to document whether it included such taxes in its proposed avoided costs. He does not concede that NWE's methodology is otherwise error free and suggests that CELP may revisit how capital costs and O&M were computed for baseload and CT plants. (p. 16)

As for retail rate impacts, Lauckhart testified (pp. 16-18) that by virtue of the MTPSC's January 31, 2002 order (No. 6353c, D2001.1.5 but also see Order 5986w in D97.9.90) approving of the sale of MPC to NorthWestern Corporation NWE's retail ratepayers are protected from the impact of higher QF avoided costs.⁵⁹ Ratepayers are protected as the order approved a stipulation that caps payments which NWE must pay for power that QFs provide. He adds that the price for contract year 2005-06 is \$32.75/MWH (citing Appendix D), well below the escalating avoided costs that NWE proposed in its June 23, 2005 filing of \$42.415/MWH plus \$65.765/kw/yr.⁶⁰ He concludes that the higher avoided costs that he proposed will have no retail rate impact as "the price limits of Appendix D will continue to protect customers from paying the higher rates that might otherwise result." (p. 17) He does not believe that NWE's ratepayers are at risk of paying higher "transition costs" due to higher QF avoided costs. They are not at risk as the "Final Order" (paragraphs 21 and 26) fixed the total amount of "transition costs" that relate to QF power. Thus, increased avoided cost payments cannot cause

⁵⁸ He does not know how long coal severance taxes have existed or whether NWE included the same in avoided cost calculations. DR PSC -111(a) As for how the first amendment addressed coal taxes, while not a legal expert, he understands such taxes are part of coal costs. DR PSC -111(e)

⁵⁹ He did not know what the impacts on NWE's capital structure would be from an increase in payments (of \$.011/kwh) for CELP's entire generation. He agrees that NWE's cost of capital would be determined by the MTPSC "...in a litigated proceeding based upon multiple factors." DR PSC -112(e)

⁶⁰ NWE explained that \$32.75/Mwh is the part of CELP's total contract cost that is in the default supply cost. It has nothing to do with the rate that CELP presently receives. The \$68.6/Mwh is the result of dividing CELP's total payments by the quantity of power delivered for the present contract year (October through March). Their actual rate based on nine months of production and payment for this July 2005 through April 2006 period is \$70.7/Mwh. DR PSC -144(b)

increased transition costs. He testified that NWE's recovery of costs for QF power is not limited to the prices in Appendix D (of "Final Order"). The stipulation approved in the Final Order allowed NWE to collect annually fixed amounts of QF transition costs, at a rate of \$25.6 million per year through contract year 2028/2029, and regardless of how much power QFs deliver. This provides shareholders some protections against cost under-recovery, but also guards NWE's ratepayers from any future increase in QF avoided costs (p. 18).

White Hall Wind Prefiled Direct Testimony: Robert Frantz⁶¹

Mr. Frantz filed direct testimony on January 24, 2006. His testimony addressed several proposals by NWE's witness Mr. Stauffer regarding rates for new QFs. First, Frantz agrees with Stauffer's proposal to use the QF-1 rate schedule instead of the STPP rate schedule for all new QFs, including those larger than 3 MW.⁶² He disagrees that QFs larger than 3 MWs should be eligible for the QF-1 rate only temporarily, up to five years or until NWE conducts a subsequent request for proposals, whichever occurs first. Frantz asserts that five years would not enable a QF to obtain financing and would violate Montana's mini-PURPA, which requires the MTPSC to encourage long-term contracts between QFs and utilities in order to enhance the economic feasibility of QF projects. According to Frantz, standard QF financing requires a twenty-year contract; five years is too short to convince lenders they will receive a return on their investment.

⁶¹ He asserts that the primary thrust of his comments is that the MTPSC must move forward to adopt rules and procedures that are fair to QFs. DR PSC -114(d)

⁶² He asserts that given the lapse in time between NWE's last testimony that he is unsure what NWE's position is on the prospective QF rates. He states to believe that the STPP rate inappropriately reflects an outdated variable cost of generation from a coal resource adding that the variable cost of coal is no longer NWE's avoided cost. He further adds that he may have overstated the situation as some QFs and NWE negotiate new rates when the QF meets its maximum contractual output. DR PSC -113
As for the STPP, Frantz may be in agreement that the basis of the tariffed rate was based upon avoided and/or opportunity costs combined with a partial capacity payment; however if limited to "short-term" contracts it will likely prohibit QF development. DR PSC -114 The forward price for 2008 is about \$60/MWH. DR PSC -119 The forward price for the next five years for baseload energy exceeds \$50.00/MWH; such prices should be considered in avoided cost calculations. DR PSC-115

Second, Frantz objects to Stauffer's proposal to adjust the QF-1 rate based on a particular project's availability. While he believes that Montana law permits the MTPSC to account for project availability and firming expenses associated with intermittent resources in setting QF rates, and, in his response to a data request (DR PSC-113), points to 69-8-604, MCA as the source of the MTPSC's authority in this regard, he asserts that an approach that accounts for the intermittent nature of a resource should also account for other resource attributes like fuel risk. As an example, he notes that while wind resources may generate more unpredictably than a coal-fired plant, they are less likely to be affected by rising commodity prices the way a gas fired plant would. In response to a data request (DR PSC-114), he states that if the utility is exposed to fuel risks pursuant to the terms of a power purchase contract, then the MTPSC should consider the historical price volatility of the fuel and resultant rate impacts when setting QF rates.

According to Frantz, accounting for the intermittent nature of some resources upfront in the calculation of standard tariff rates would cause rampant confusion and would be difficult to administer. He recommends that the MTPSC focus on establishing a fair avoided cost tariff for prospective QFs. If a QF and NWE are unable to mutually agree to the tariff rate, or another rate, the MTPSC should determine a rate in a separate proceeding. Any unique characteristics of the QF can be considered in that proceeding.

Third, Frantz asserts that the MTPSC's rule requiring QFs larger than 3 MW to obtain long-term contracts through utility resource solicitations probably violates federal and state law. He points to other states where QFs larger than the state's threshold are eligible for long term contracts with an integrated resource planning-based avoided cost rate.⁶³ In these states, if the utility and a QF cannot agree on an integrated resource planning-based rate, the MTPSC conducts a contested case for the purpose of setting a specific rate for the QF. In contrast, according to Frantz, the MTPSC has chosen not to arbitrate disputes, as required by law. Instead, he asserts, if a QF in Montana doesn't like a tariff rate and complains to the MTPSC, the MTPSC simply applies the tariff rate. This approach, he says, renders the complaint process in Montana meaningless. In response to a data request (DR PSC-114), Frantz says he based this testimony on his understanding of

⁶³ The states that he identified include Idaho, Wyoming, Utah, Oregon and Washington.

the MTPSC's decision in Order 6444c, Docket D2002.8.100; his main point is that the current system is not rational or equitable for new QFs.⁶⁴

Frantz states that PURPA is relevant today because NWE and the MTPSC are looking for ways to check PPL Montana's market dominance. He says developing alternative generation is one way to do that. He asserts that PURPA can be a powerful tool for creating opportunities for developers because it requires that utilities fully recover QF-related costs. He notes that PURPA encourages renewable resources that diversify the nation's generating portfolio and reduce dependence on fossil fuels. These goals are as relevant today as they have ever been, he says, given that natural gas costs \$7.00/Dkt and oil costs over \$60.00/barrel.

Frantz recommends that the MTPSC adopt Idaho's QF approach. Idaho maintains a tariff rate for fueled and non-fueled projects under 10 MW. QFs 10 MW or larger are eligible for an avoided cost rate derived from an integrated resource planning process. In response to data request PSC-117, Frantz suggests that the MTPSC modify NWE's default supply process to include a more formal review and approval of a base case price forecast that would be the basis for long-term QF contracts. If the utility and a QF cannot mutually agree to a rate or contract terms, Frantz recommends that the MTPSC conduct a contested case to settle the issues. He defers to NWE to set the tariff rate, since that is the NWE's obligation under PURPA. However, he asserts that the current rate of \$32.75/MWH is significantly below the expected market for the next five years, as demonstrated by: 1) forward prices for power traded at the Mid-C, 2) Northwest Power and Conservation Council (Council's) price forecasts, and 3) NWE's price forecasts in its

⁶⁴ Frantz erred in citing to the MTPSC staff adding that he meant to cite the MTPSC's decisions in Order 6444c. DR PSC -113. Order 6444c addressed a complaint by Whitehall Wind pursuant to 69-8-603, MCA requesting a rate determination. Order 6444c determined that Whitehall Wind is a QF larger than 3 MW and is eligible for a long-term contract with NWE pursuant to the MTPSC's rules in ARM 38.5.1905. Under those rules, in order to obtain a long-term contract, a QF must be selected by the utility as a result of competitive resource solicitation. Between solicitations, the QF is eligible for the utility's short-term tariffed avoided cost rates or a negotiated short-term rate. Order 6444c noted that the MTPSC is in the process of reviewing both the current short-term tariff rate and its basis.

2005 Default Supply Resource Procurement Plan.⁶⁵ He concludes that NWE's avoided costs have increased and the tariff schedules should be adjusted accordingly.

NWE Rebuttal Testimony: Mark Stauffer

On February 28, 2006, NWE filed the rebuttal testimony of Mr. Stauffer. He rebuts the testimony of both CELP's witness Lauckhart and of WHW's witness Frantz.⁶⁶ As for Lauckhart, he responds to allegations that NWE made several calculation errors in its 2005 QF rates including that NWE failed to: 1) use the incremental cost of capital (ICC), 2) include coal severance taxes and 3) calculate correctly the Unit Labor Cost (ULC) escalation. He first addresses the last two issues, admitting to err in calculating the ULC and denying an error involving severance taxes.⁶⁷

Stauffer characterized Lauckhart's testimony on the issue of using the ICC as a new and significant issue (pp. 1-11). He admits to not using an ICC or accounting for taxes when computing the QFLT rates that CELP receives today but testifies that both were used when the rate was "originally calculated."⁶⁸ He explained that NWE escalated the portions of the QFLT rate that are partially levelized by applying three U.S. Government inflation measures to escalate values for variables in the Order 4865 rate

⁶⁵ In addition, he stated that NWE files monthly trackers. The forward price for the next five years for baseload energy exceeds \$50.00/Mwh; such prices should be considered in avoided cost calculations. DR PSC-115

⁶⁶ Note that in addition to CELP, Hanover Hydro and Pine Creek are impacted by the QFLT rates. (see DR PSC 124(b), but also see DR PSC -126(c))

⁶⁷ He estimates the magnitude of the ULC error for the escalating and partially levelized rates. As for rate corrections, he also explains how in D2002.7.80 interim rates were corrected, adding that on no occasion has a rate that was finally approved been corrected; the time-value-of-money reflects the WSJ's published Prime rate. DR PSC -121
As for errors and true ups to interim approved rates, he notes that NWE's September 28, 2005 submittal requested that the QFLT escalating and partially escalating rates for contract years 2004-5 and 2005-6 be corrected for known errors, adding that CELP Hanover Hydro and Pine Creek will all be impacted. DR PSC -126(a),(c)

⁶⁸ The escalating and partially levelized QFLT rate components and the system lambda (STPP) are all influenced by the cost of coal and hence the coal tax. DR PSC -121(c)

formulas.⁶⁹ The annual carrying charges for C 3&4 and the Peaker require a cost of capital measure and NWE has, in turn, used the “Allowed Rate of Return” (ARR) from MTPSC Order 6271(c).⁷⁰ In contrast, he testified that Lauckhart’s cite to Order 4865 (Finding 34) is to a section of the order that explained how to compute the “new” QFLT rate, a rate that is no longer computed.⁷¹ NWE escalates portions of existing rates. He concludes that Finding 34 has “no bearing” on the rate escalation process. He adds that consistent with FOF 34, NWE used the appropriate ICC, along with taxes and other expenses, to compute the levelized fixed charge factor (LFCF) in the original calculation of the rates that are in CELP’s 1994 contract (p. 3). In contrast, he asserts that the ICC is applicable to the cost NWE would incur if today it constructed a baseload or peaking unit. He believes that the MTPSC should reject CELP’s opportunistic attempt to increase its rate.

Stauffer elaborates on why FOF 34 is irrelevant. (p. 4) Again, he testifies that FOF 34 (Order 4865) applied only to new QFLT rates. The LFCF is used every year in the rate escalation process as an input to compute the annual carrying charges for C 3&4. The LFCF includes depreciation, state and federal income taxes, return on equity and debt, insurance and property taxes. He asserts that “these figures” (assumably values for the components of the LFCF) have been held constant since 1988 (p. 4). He adds that NWE complied with FOF 34 when in 1984 it originally computed CELP’s rates (p. 5). He concludes that FOF 34, that is titled “Long-Term Rates,” clearly deals with the “original calculation of the rates and not the annual escalation calculation.” (p. 5) He explains that the annual carrying charge (ACC) is applied to the levelized cost to compute the cost on a levelized basis. NWE applied the ACC to the escalated annual construction

⁶⁹ In response to DR PSC -109(e) Lauckhart explained that the error that he alleged does not impact the partially escalating rates.

⁷⁰ NWE explained that the ARR is used (per D81.2.15) to compute the baseload and the peaker real carrying charge for the annual escalation process. In regard to D83.1.2, the ARR was not used in the original calculation of the long-term rate option as the then current ICC was used. DR PSC -141(c),(d)

⁷¹ The D81.2.15 orders provide formulas to compute the QFLT rates. DR PSC -122(b)

cost variables for both C 3&4 and for a peaker. These escalated construction costs and the ACCs are four of the rate variables in the partially escalating rates.

Stauffer also concludes that from an “accounting perspective” the use of the ICC to compute the ACC is incorrect. To include it now would clearly comprise “double counting” (p. 6).⁷² He testifies that Lauckhart’s apparent confusion stems from the use of “annualized capital costs” and “updated annually” in FOF 34. These rates were computed annually and were available to “new” QFs, until 1984 when the QFLT rates were suspended and when NWE ceased to compute “new” rates (p. 7). He adds that Lauckhart could not provide a clear reference requiring use of an ICC in the annual escalation of existing rates.⁷³ Stauffer concedes that NWE has now used the ARR for several years to compute the ACC for both C 3&4 and a peaker and that such use of the ARR is, “at this point of the rate escalation,” appropriate.⁷⁴

If, however, the MTPSC decides that the ICC should be used, then all inputs associated with the variable, such as the current tax, insurance rates should be updated (p.7). While NWE can update the ARR for debt rates, he notes that NWE does not have a fresh cost of equity. He adds that Lauckhart’s value of 13.15% is speculative (p. 8). If the MTPSC approves of a 13.15% ROE in its next rate case, NWE will use the same to compute CELP’s rates. He testified that an appropriate capital structure is 50/50 with the currently approved 10.75% cost of equity and use of recent and planned financings for an incremental debt cost.⁷⁵ As incremental taxes were included in the “original” LFCF, it

⁷² Lauckhart’s proposal would result in a double counting of taxes. Taxes are in the levelized fixed charge factor and the MTPSC has never required that it again be accounted for in computing the current cost of capital. DR PSC -122

⁷³ He asserts that the contract makes no mention of the cost of capital related to the calculation of rates. DR PSC -122(c)

⁷⁴ Order 6271c makes no reference to avoided costs but is the source for the ARR. DR PSC -122(d)

⁷⁵ In 2004, NWE secured a 10-year taxable debt issue with a 5.87% coupon. Its upcoming secured 17-year tax exempt financing will have a coupon of about 4.65%. NWE’s “unsecured revolver,” also incremental debt, has a spreads of 1.125% over LIBOR for all borrowings that occur under the facility through October 2009. Stauffer explained that

would be double counting to now gross up this ICC as Lauckhart suggests (p. 8). He adds that if Lauckhart really wants NWE to recalculate the carrying charge rates with a new ICC, then NWE would essentially recalculate the LFCF. The likely result of using a new ICC, including debt placements, will be to lower both carrying charges and rates.

Stauffer testified that Lauckhart's analysis and estimate of the impact on ratepayers is "materially" incomplete (p. 9). First, CELP's rates would decline if the original calculation was updated using today's lower capital rates. In turn, use of the ICC in place of the ARR will result in more unstable rates, increased uncertainty and impacts on NWE's financial exposure. Second, a 13.15% cost of equity is inappropriate (p. 10).

Stauffer explained that once Order 4865's rates were suspended NWE proposed a method that continued to calculate the rates in a manner similar to the "new" rates (p. 10).⁷⁶ NWE later proposed a method that retained the basic formulas and that included escalators for the variables used in those formulas. The MTPSC approved the proposal which has been used since that time. Annual escalation has been approved numerous times since 1984. He explained that the cost of capital is used in the annual updates of the ARR as at the time that the Order 4865 rates were suspended NWE and MTPSC had

the ICC associated with 10.75% equity is about 8.143%. DR PSC -124(e) If an ICC is determined, then NWE suggests using debt costs (see DR PSC -125(a)).

⁷⁶ He corrects his testimony to state that NWE continues to compute the STPP rate pursuant to Order 4865; the reference was to the QFLT rates. (DR PSC -123) He also attempts to clarify his testimony in response to DR PSC -126(d): *Regarding the NPV calculation in the 1984-5 filing, NWE used the current marginal cost of capital (MCC) and the most recent construction cost estimates for C 3&4 and the Peaker Unit. Current tax information was also used to arrive at a MCC with tax effects included. The following year the MCC and tax rates were updated and revised C 3&4 construction costs were used. This continued through the 1988-9 rates. From 1988-9 through the present, the variables used for the NPV have been held constant at the 1988-9 levels. That is, at the 1.372 and 1.281 (sic) levels for the baseload and peaker units.* (italics added). Stauffer explained the carrying charge calculation, escalation methods and the inflation indices used through time. In a follow up response (DR PSC -143), NWE explained that the 1.372 and 1.281 values are ratios that represent how much money (\$1,372 and \$1,381) an owner of a baseload or a peaker unit must recover for every \$1,000 ("TPV") that it invests if it is to recover costs associated with taxes, return, depreciation and insurance.

to resolve a unique problem.⁷⁷ A method was needed, that incorporated the intent of 4865, and that escalated values for rate components. He asserts that NWE and the MTPSC arrived at the present method of updating over the course of filings and approvals in the years following the suspension of new rates. Thus, the ARR was, and it remains, consistent with the use of the ICC in the originally calculated carrying charge (p. 11).⁷⁸ He asserts, that this is consistent with “normal regulatory accounting treatment for resources that the Order 4865 rates were intended to avoid.” Otherwise, each individual unit in a utility’s portfolio would collect costs based on a different ICC. To quote: “...*the effect of these incremental cost of capital are captured in annual carrying charges that is essentially an ICC, as reflected in the NWE proposal and as previously approved by the MTPSC.*” (italics added, p. 11).

Stauffer testified that due to the lack of explicit direction the “annual escalation process” is becoming unmanageable (p. 11). This vacuum provides an attractive means by which QFs may attempt to inflate rates. The existing CELP rate, of \$76/MWH, is in “gross excess” of what a coal unit rate in 1984 would currently be, which was what the avoided cost rates were intended to represent avoidance of.⁷⁹ The Council’s estimate of a

⁷⁷ Given that there was no need to then compute the rate anew, a means by which to escalate the rate had to be determined (p. 10). He adds that due to the absence of any explicit direction a method was created that incorporated the intent of Order 4865.

⁷⁸ The ARR has been used since the 2001 filing. Prior to 2001 the financial department computed an ICC to analyze new incremental generation additions that was used in annual updates; but NWE no longer is in the resource development business for the purpose of rate-basing resources. Thus, NWE does not have an ICC applicable to generation. DR PSC 124(a),(d)

⁷⁹ The \$76/mwh is based on the present rates of \$57.9/Mwh plus \$111.97/kw/yr at a 70% capacity factor. The tariffed rate would be \$68.6/mw/hr. DR PSC -127(a) NWE also compared the payments that CELP received (pursuant to its revised contract) with those that it would have received pursuant to the MTPSC’s order. DR PSC -127(b)

NWE was asked about a letter that MPC’s Mr. Robert Labrie sent on June 20, 1988 to MPC’s Mr. Thomas Worrington and in which avoided costs were estimated in the range of \$.04081/kwh (1989) and \$.06819/kwh (2010). DR PSC -142

new coal unit's total cost was \$43/MWH in 2005.⁸⁰ He adds, "this confusion has been of considerable benefit to CELP." (p. 12) The confusion is unnecessary if the various rate components are computed in compliance with the intent of Order 4865 (FOF 37). (p. 13).

Stauffer next provided an overview of the Order 4865 rates. Such rates were based on actual C 3&4 costs, including coal and O & M (p. 12). Rates were offered in three formats: escalating, partially levelized and nominally levelized. QFs had a choice between forecast and actual inflation (p. 13). Thus, what is discussed "here" is the escalation of rates, not the re-computation of rates. Computation of the escalating piece is not intended to re-compute annually the rates with a new incremental cost of capital. The ICC is essentially locked in, in the form of the LFCF, for the duration of these rates.

Stauffer recommends using three indices, the Unit Labor Cost, the Fixed Investment Non-residential and the GNP-IPD (p. 13).⁸¹ The first two are weighted 20% labor and 80% investment for capital variables, and 40% labor and 60% capital for O&M variables, with all weightings derived from an EPRI study (cited in Order 4865, page 31, Footnote 2) of relative costs of capital and O&M for coal and gas generators. The only other variable is the "all-inclusive" prior year's cost of coal for C 3&4 but escalated by one year using the GNP IPD. This, he asserts, is fair, equitable and simple and what the MPSC should adopt for QFLT rates (p. 14). He explained that the GNP IPD is used to compute the real annual carrying charge to then arrive at a nominal charge which is applied to the escalated capital costs (p. 14).

In regard to Frantz's testimony suggesting that NWE's present offering is insufficient to develop their projects, Stauffer notes that RFP opportunities will be offered on a continual ongoing basis (p. 14). QFs will be able to win contracts through these processes and therefore a "long-term" contract outside the RFP process is not necessary. A five-year contract at rates that NWE presently pays its RFP winning bidders is a significant encouragement for QFs. As for Frantz's suggestion that a single

⁸⁰ The \$43/MWH value is a real levelized value in 2006 dollars and is comparable to CELP's rates. DR PSC -144(a)

⁸¹ Stauffer explained that the recommended approach has been used since 2001 as proposed by NWE. DR PSC -128

rate offered to each QF discriminates against wind QFs, Stauffer testified that the single rate is structured so that each QF is paid the full value for what it delivers. To ignore that wind generation is intermittent, would discriminate against all other QFs. And, if NWE paid for all “nameplate capacity” even if not delivered, someone would have to pay for the additional costs. Frantz’s suggestion that accounting for the intermittent nature of any resource would cause rampant confusion is wrong, according to Stauffer, as NWE’s simple rate does take into account for the intermittent nature of “some” resources (p. 15).

Stauffer was also asked about the merit of using GenTrader® to estimate avoided costs (see DR PSC -132 and follow up responses to DR PSC -151) He responded that GenTrader® is a dispatch model that is used to replicate the operation of hypothetical units in a market environment to analyze various potential resource combinations relative to customers’ resource needs. At present, NWE has minimal ability to dispatch, the exception is the 50Mw Basin Creek facility. He adds that the primary purpose of developing a Resource Procurement Plan is to guide the RFP process and in this regard neither GenTrader® nor the RPP provides relevant costs. He further adds that prior to an RFP process NWE does not know what resource options exist, but once the winning bids are selected it will have relevant QF cost information. He asserts that the costs of Basin Creek are included in NWE’s currently proposed QF rates. Stauffer explained that the \$45 value is a 20 year nominally levelized value that excludes transmission costs (BPA’s are presently \$3.5/Mwh). He explained that the \$45/Mwh value is based on the NWPPC’s forecast of what the levelized value of the regional Mid-C market will be for the next 20 years. NWE asserts that the \$45/mwh is used to determine DSM acquisition levels.

When asked why NWE opposed basing QF rates on opportunity costs, Stauffer responded that to base firm power rates on the spot market is inconsistent as NWE enters into long-term contracts to avoid the volatility of the spot market environment. Through the RFP processes NWE procures stable and reasonably priced contracts that indicate the value of QF power. The spot market is not a source of stable priced power and it would be a disservice to ratepayers to enter into contracts that require paying a firm contract at an unstable spot-market based price. DR PSC -129(a) He declined provide for calendar year 2005 the weighted annual average rate of sales that NWE has made, adding that

neither NWE's accounting system nor invoices have the necessary detail to separate day ahead and real time transactions.⁸² DR PSC -129(c) He explained that Mid-C purchases require paying BPA \$3.5/Mwh plus 1.9% for losses; sales at the same point involve the same BPA charges but also involve a \$4.66/Mwh plus 4% loss charges on the NWE system.

Stauffer was also asked, about the inclusion of a capacity payment with the STPP rate. He responded that whereas NWE has proposed a capacity payment in its QF1 rate, based on a NWPPC peaker cost analysis and using incremental capital costs, if required, NWE would propose to use the same capacity payment as the basis for one half (1/2) of an STPP capacity payment. DR PSC -123(a)

CELP Proposed Surrebuttal Testimony: Richard Lauckhart

On March 10, 2006, the MTPSC received the proposed surrebuttal of Lauckhart. His testimony clarifies the testimony of NWE's witness Stauffer. He asserts that Stauffer raised a new issue when he asked the MTPSC to adopt new and different QF calculations. He also asserts that Stauffer's testimony essentially concludes that both the MTPSC orders and the CELP contract are not to be followed if the results seem unfair. NWE intentionally changed the method used to compute rates in an attempt to harm CELP (p. 2).

Lauckhart concludes, based on NWE's request of the MTPSC to change the "escalation formula," and a reading of Owen Orndorff's Affidavit (filed March 10, 2006), that NWE's proposal violates both the MTPSC's orders and the CELP contract. The MTPSC should not use this proceeding to debate alternative avoided cost rate methods. He understands Stauffer's testimony to assert that the ICC is used when the rate was originally computed and is not meant to be used with annual adjustments. He testified that the only method that is allowed by MTPSC order, or the CELP contract, is the

⁸² NWE did not dispute the accuracy of publicly available data accessible at the FERC: <http://www.ferc.gov/docs-filing/equ/data.asp> DR PSC -130 In a follow up data response, NWE explained that it did not provide the FERC the underlying purchase price information. Rather that information derives from market suppliers. DR -148(a) NWE continues to hold, however, that short-term market purchases and sales are not an appropriate source for long-term avoided cost information. (DR PSC -148(c))

overall ICC, including tax effect, not the embedded cost of capital (p. 3). He adds that Stauffer is proposing to litigate the method used. He further adds that Stauffer claims that the ICC calculation must result from a MTPSC hearing and not from an avoided cost docket (venue). Whereas Stauffer asks the MTPSC to decide which available measures of inflation are appropriate for escalation, he testified that NWE is avoiding the fact that “alternative approaches are not an option.” Neither is permitted by the MTPSC’s decision or CELP’s contract (p. 3).

Lauckhart next explained why the possibility that the ICC determination “might result” from an involved MTPSC hearing is not an “appropriate basis” to modify the method for performing the calculations (p. 4, first Question).⁸³ He concludes that the MTPSC must in this proceeding order NWE to calculate the ICC in accordance with the MTPSC’s order and the CELP contract (p. 4). As for Stauffer’s testimony that the ICC would usually result from an MTPSC hearing, not an avoided cost filing, his concern is that “embedded cost of capital” proceedings can be involved and the PSC’s avoided cost orders do not require embedded cost of capital calculations. He adds that if NWE wants to change how the annual escalation is to be performed, then NWE would need to negotiate a contract change with CELP (p. 4).

Lauckhart testified that there is “evidence” that CELP was supposed to get prices that increase in years prior to and after year 15 of the CELP contract (p. 5).⁸⁴ He adds that based on the “original contract” (’84) it is clear that CELP “would have” received “partially levelized energy rates of \$.03751/kwh for the contract’s duration. However, CELP accepted \$.0222/kwh in the first year in exchange for increased rates over time and

⁸³ In a follow up response to DR PSC -134(b), CELP explains that his surrebuttal is intended to bring focus to the requirements of how to calculate avoided costs in D83.1.2’s orders, as required by Tables I and II in CELP’s first amendment. CELP adds that NWE ignored Order 4865, paragraph 34.

⁸⁴ In response to a follow up data request (DR PSC -135(e) but also see PSC -136(a)), CELP conceded that D83.1.2 did not guarantee that partially levelized tariff rates will increase each year of the contract; the escalating portions of energy and capacity rates can normally be expected to increase with various indexes and the operating costs of C 3&4. Starting with contract year 16, the first amendment provides a contractual formula to determine escalation of CELP’s energy and capacity rates. The formula does not guarantee annual escalation but provides for inflation.

for being “relieved of security requirements” required by Appendix D of the CELP contract (p. 5).⁸⁵ He adds that CELP’s agreement to accept reduced energy payments in contract year 1, in exchange for increased payments over time, is “evidenced” in “Table 1 of the March 1988 first amendment to the 1984 agreement.” He further adds that “Amendment 1” clearly states that these rates were to be “increased based on the compliance filing” pursuant to D83.1.2 orders that, in turn, required the use of a tax adjusted ICC.⁸⁶

Lauckhart testified that CELP did not previously raise the issue involving NWE’s failure to use the “after tax” ICC as it was not relevant to the computation of CELP’s avoided cost rates until the 16th contract year (2004/05) and this (surrebuttal) is the first chance that CELP has had to raise the issue (p. 6). Whereas Stauffer testified that use of an ICC method is incorrect, Lauckhart testified that in 1982 MPC raised “accounting basis” arguments, ones that the MTPSC in Order 4865b (paragraphs 16-24) apparently rejected (p. 6, first Q and A). He disagrees with Stauffer that the ICC findings of fact in Order 4865 only regard how “new rates should be calculated” and not apparently the “administration of existing rates.”⁸⁷ He adds that CELP has a long term rate with NWE

⁸⁵ As for the \$.0222/kwh rates relevance, the fixed energy rate in the first amendment reflects the de-levelized rates which make up the original partially levelized tariffed rate. DR PSC -136(b) In a follow up data request, NWE explained when and how it received MTPSC approval of the amended contract between MPC and CELP. DR PSC -149(d) Whereas CELP asserts to have accepted \$.0222/kwh in the first year, the actual rates that NWE reports to have paid CELP are different (see DR PSC -150(a)).

⁸⁶ In response to a follow up data request (DR PSC -135(a),(b), CELP identified those parts of D83.1.2 orders and its contract that discuss tax adjusted ICC estimates. CELP explained in a follow up data response what “increased based on” means. DR PSC -136(c)

⁸⁷ In response to DR PSC -137c, CELP states that MPC and CELP agreed in the first amendment to base annual rate determinations on MTPSC decisions in D83.1.2 (orders 5017 Findings 15 and 29, 5017a). CELP adds that the ICC is a specific component in determining partially levelized rates. CELP adds, in response to DR PSC -138a, that pricing “under the contract” refers to the requirement to recalculate CELP’s energy and capacity rates starting with the 16th contract year, as required by the first amendment. CELP explained that had it defaulted on its contract in the 14th year and ceased operating as a QF that there was no agreement for NWE to make any necessary compensation. DR

and that nothing in the order says the calculation is not to be used with long term rates: “...it requires that the incremental cost of capital including tax effect, be updated every year,” (sic) Although NWE (f/k/a MPC) ceased offering “these rates to new QFs in 1984” he testifies, in rebuttal of Stauffer, that nothing in MTPSC orders allows it to stop making these calculations simply because NWE ceased offering these rates to new QFs: “As a consequence, it should be clear that each utility must file annually (June of each year) rates reflecting the Commission’s orders in Docket No. 81.2.15 so long as one or more qualifying facilities have contracted for the long-term rate option as defined and computed in Order Nos. 4865a, b, and c.” (citing Order 5017a, paragraph 9, emphasis excluded, italics added). He testified that the MTPSC orders (4865a, 4865b, 4865c, 5017 and 5017a) that build upon Order 4865 must also be considered. He adds that the CELP contract incorporated these “1980’s vintage Commission ordered calculations for purposes of determining pricing under the contract.” (page 9, first Q and A).

NWE Surrebuttal Testimony: Mark Stauffer

NWE filed on May 4th the surrebuttal testimony of Mr. Stauffer. His testimony reiterates the issues related to CELP to demonstrate that the premise that CELP used is fictitious and to respond to the misrepresentations that CELP made. He holds that CELP’s misrepresentations appear to create as much confusion as possible. He also finds an inconsistency in CELP’s rationale. On one hand, CELP asserts that prior MTPSC

PSC -138(b) Apparently, after year 15 there are no predetermined fixed rates and CELP has no idea of how MPC de-levelized rates; also, there are no liquidated damages in any year because MPC de-levelized all of CELP’s rates in favor of annual calculations after the 16th year. DR PSC -138(c),(d),(e) CELP explained that the only agreed upon assumptions that would be used to modify annually the contracted rates are in Tables I and II of Attachment 1 of the first amendment. NWE holds in response to CELP’s response to DR PSC -138(c) that the MTPSC’s role is to approve annually QFLT rates; the use of those approved rates to update CELP’s rates is a contract issue between NWE and CELP. See DR PSC -149(e)

In a supplemental response, CELP augmented its response to DR -138(d). Whereas initially CELP stated to have “no idea” how MPC delevelized rates, in the augmented response CELP states to have located a “significant document” that clarifies how MPC delevelized rates for QFs, including CELP. Delevelization was achieved by withholding

actions are irrelevant to CELP's rates. On another hand, CELP "scolds" NWE for violating MTPSC orders. This inconsistency makes it nearly impossible for NWE to understand CELP's rationale (MAS -12).

Stauffer identifies three issues: 1) should the annual escalation of rates use the ICC (incremental cost of capital) or the MTPSC's approved ARR (allowed revenue requirement); 2) should NWE account for "tax effects" a second time when escalating the capital costs for both Colstrip and a peaker; 3) what measures of inflation should be used to escalate rate variables. Importantly, he disagrees with Lauckhart's testimony that these issues are "contract issues." Rather, they are rate calculation issues that the MTPSC must determine.

Stauffer explains how Lauckhart in rationalizing CELP's surrebuttal testimony misrepresents the facts in order to confuse the issues. First, as for CELP's allegation that NWE raised a new issue, involving new and different rate calculations, he testified that NWE made no new rate calculations. As for CELP's position that NWE seeks to re-litigate prior MTPSC orders, he asserts that NWE is not unwilling to pay CELP \$69 rates. He provides rate and cost information to demonstrate the absurdity of the claims that NWE is trying to economically harm CELP, what he labels as "probably the most lucrative contract of any generator in the region today."⁸⁸ He denies changing the method but admits to making a change in 2001 to use the ARR as NWE was no longer in the generation business and it therefore did not have a generation-specific ICC.

Stauffer also clarified that NWE considers in a different light changes that result from changed data inputs. Whereas changes in the methodology would entail a change to the formulas, a change in inputs is to simply use more reasonable sources of information

parts of the levelized rate in the early years of the contract as security, with MPC repaying the withheld funds to the QF in the later years of the contract.

⁸⁸ In March 1, 2006 Rebuttal testimony, he asserts that the existing CELP rate, of \$76/MWH, is in "gross excess" of what a coal unit rate in 1984 would currently be, which was what the avoided cost rates were intended to avoid. The Council's estimate of a new coal unit's total cost was \$43/MWH in 2005. See Footnote Number 90 for further discussion. In response to DR PSC -149(a), NWE was asked to explain what part of CELP's "lucrative" rate stems from having received below cost rates in the early years, NWE only responded that CELP is presently receiving and will continue to receive, for the duration of the contract, rates in excess of the original rate they signed up for.

(MAS -13). To illustrate, NWE labels a change from an ARR to an ICC an input substitution, not a change in methodology (MAS -14). In any case, he asserts that the difference in opinion between CELP and NWE stems from different interpretations of FOF 34 (Order 4865, Docket 81.2.15). He adds that over time, NWE has both updated some variables, held others constant and substituted various sources for information on escalation indices. He cites to NWE's response to DR PSC -126(d) as pertinent to what has transpired since 1984.⁸⁹

Second, Stauffer takes issue with Lauckhart's testimony that asserts:

"...this proceeding is designed to simply make the annual calculations Required by prior Commission orders and in accordance with contract requirements." (italics and emphasis added)

He disagrees that "contract requirements" have any relevance in this proceeding, as they are rightfully before a court and not the MTPSC. He adds that CELP's notion that its contract is relevant to rate escalation issues is absurd.

Third, Stauffer rebuts that part of Lauckhart's testimony that asserts to have not proposed anything new. He holds that Lauckhart's double counting of tax effects is certainly a change. As for CELP's suggestion that the MTPSC's choice is between the use of NWE's embedded costs of capital or the tax adjusted ICC that CELP proposed, he disagrees and asserts that the "choice" is between the embedded cost of capital or the ICC. He asserts that CELP sought to "co-join" the issues to give their absurd double taxation proposal credibility (MAS -10,11). As the ICC issue "may have merit," he separates the two issues and asserts that because the tax adjusted ICC was in the initial calculation of rates, and because NWE continues to escalate the tax adjusted cost of capital each year, this should not be an issue in this case and not even CELP has

⁸⁹ NWE's response to DR PSC -126(d): *"Regarding the NPV calculation in the 1984-85 filing, NWE used the current marginal cost of capital (MCC) and the most recent construction cost estimates for Colstrip 3&4 (C34) and the Peaker unit. Current tax information was also used to arrive at a MCC with tax effects included. The following year the MCC and tax rates were updated and revised C34 construction costs were used. This continued through the 1988-9 rates. From 1988-9 through to the present, the variables used for the NPV have been held constant at the 1988-9 levels. That is, at the 1.372 and 1.381 levels for the baseload and peak units respectively. This effectively locked in the MCC rate and the tax rates at the 1988-9 level."* (italics added)

suggested that taxes should be counted twice. He adds later that, with the “ratio” of rates combined with CELP’s double counting of taxes, CELP would receive a windfall profit for the remaining term of its contract, of about \$15.8 Million per year for 20 years (MAS-9, 10). He also adds that the impact of CELP’s recommendations will have no direct pass-through impact due to increased costs on ratepayers; however, indirect impacts would be significant as any unrecovered costs would impact NWE’s financial health (MAS -17). Thus, a \$16 million disallowance, that rating agencies classify as “imputed debt” and the appearance of an unstable contract, would be viewed negatively.⁹⁰

Whether NWE should use the embedded or the ICC is a separate issue. NWE agrees that, if directed, it will use the ICC. NWE’s ICC is 8.143% which contrasts with the 8.464% ARR used in the annual rate calculation.

Fourth, as for “escalators” and Lauckhart’s assertion that NWE would need to negotiate with CELP for a change in the contract, Stauffer responds that Lauckhart has a fundamental misunderstanding of how QFLT rates are escalated. NWE has proposed “indexes” for MTPSC approval and NWE is under no obligation to negotiate these matters with CELP. Again, he holds that CELP’s notion that its contract is relevant to rate escalation issues is absurd. As for changes in the escalation rates, he explained how beginning in 1989-90 NWE changed one (Handy Whitman Index – HWI) index to a weighted average measure of Data Resources Incorporated indexes (MAS -15, 16). In 1995, NWE proposed changing the construction cost index. And in 2003 NWE proposed using a capital cost escalator of 20% unit labor and 80% fixed investment and an O&M escalator of 40% labor and 60% fixed investment. He notes that, with the exception of the present consolidated dockets, all changes he described were approved (MAS -16).

Fifth, and in regard to Lauckhart’s testimony that the issue of computing “after tax incremental cost of capital” was not relevant until year 16 of CELP’s contract (contract year July 1- 2004 to June 30, 2005) and that this is the “first chance” that CELP has had to raise the issue, he notes that since CELP has intervened in each of the consolidated dockets, it has had an “open ended” opportunity to provide input. When

⁹⁰ Stauffer testifies that “this project” (CELP) is owned by out of state capital investment institutions (including Michael Dell’s Paragon Capital) and general partners.

CELP (Orndorff) filed testimony in the first of these three dockets it raised neither the double counting of taxes nor the use of the average rate of return issues.

Stauffer testified that 2004-05 is not the first relevant contract year's rates because year 16 rates are based on CELP's year 15 rates. The year 16 rates are based on CELP's year 15 rates times the ratio of the 2004-05 rates over the 2003-04 QFLT rates.⁹¹ In addition, while the 2003-2004 rates are the first rates that directly impact the year 16 rate calculation for CELP, in reality all the QFLT rate filings are relevant to CELP's present rates. He appears to suggest that the ratio approach to computing CELP's rate increases, which began in year 16, is unique to CELP (p. MAS-9). He adds that the numerator and the denominator in the ratio must be calculated using the same method.⁹² Since NWE's ratios are lower for energy (0.8589) and capacity (0.8976) than result from CELP's advocacy (1.6079 and 1.4855 respectively), he explained that the difference stems from the lower real cost of capital. Inflation of 2.51% exceeded the prior year's rate of 1.05% and therefore lowered the same nominal capital cost of 8.46% (MAS -11). Because "recent refinancings" are an appropriate measure of NWE's ICC, he asserts that it is appropriate to use the 8.143% ICC for the three years of rates decided in this proceeding (MAS -12).⁹³

⁹¹ For an explanation as to how CELP's rates were computed, NWE also turns to Tables I and II of the first amendment to the CELP contract. The first amendment shows how the levelized portions of the partially levelized rates were converted to escalating rates for years 1 through 15. Stauffer explains that the difference between the levelized rate and the escalating rate is what CELP would have paid for security in the front years. He adds that all of the values were derived from the Order 5017 et al methodology. Instead of CELP receiving the full levelized rate and paying security into an escrow account, the security payment was removed from their rate, and they were simply not overpaid. The money they would otherwise have received is now being paid to them, with interest, in that from the 11th year on the CELP rate is greater than the levelized rate. The escalating part of CELP's rate was not affected by the first amendment. DR PSC -144(c) CELP's rates did not deviate from the MPSC methodology. DR PSC -144(d) NWE asserts, however, that the ratio approach used to compute CELP's rates is not found in any MTPSC order. DR PSC -145

⁹² The equation is illustrated (MAS-9):
$$\text{CELP YEAR 16 Rates} = [\text{CELP YEAR 15 rates}] * [(\text{QFLT 2004-05 rates})/(\text{QFLT 2003-04 rates})]$$

⁹³ As for refinancings, Stauffer explained that NWE's ICC of 8.143% was based on one debt refinancing and the Order 6698a debt ceiling of 5.2%. DR PSC -147(d)